Kemper County Storage Complex

Proposed Injection Well 19-2

Mississippi Power Company

Conceptual Modeling

40 CFR 146.84

Facility Information

Facility Name:	Kemper County Storage Complex Well Name: MPC 19-2
Facility Contact:	Mississippi Power Company Environmental Affairs P.O. Box 4079 Gulfport, MS 39502-4079
Well Location:	Kemper County, Mississippi Latitude: 32.6130560 Longitude: -88.8061110

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List of Acronyms/Abbreviations

AoR	Area of Review
CCUS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
ECO_2S	Establishing An Early Carbon Dioxide Storage
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	feet
mg/L	milligrams per liter
MMt	Millions of Metric tons
MPC	Mississippi Power Company
PCC	Porters Creek Clay
PISC	Post-Injection Site Care
psi	Pounds per square inch
RCA	Routine Core Analysis
SS	Sub- Sea
TMS	Tuscaloosa Marine Shale
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A.0 Computational Modeling Details 40 CFR 146.84 (c)(1)

A.1 Modeling Parameters

Relevant hydrogeologic model parameters for multiphase flow modeling include porosity, permeability, relative permeability and capillary pressure, formation compressibility, storage capacity, formation (fluid) pressure, and formation temperature (EPA 2013[1]). A detailed description for the relevant parameters selected for the initial assessment, the source of this information, and the rationale for their use are provided below. This section is directly linked to the *Area of Review* (Section 3.0) as it details all the inputs from the computational model which was built and used to define the AoR at the Kemper County Storage Complex.

A.1.a *Porosity*

Non-Injection Zones Saline Reservoirs Porosity

This section includes porosity information for all the sandstone formations except the targeted injection zone of the Paluxy Formation. Porosity values were derived in each formation by taking an average of the neutron porosity and density porosity logs collected from the Mississippi Power Company (MPC) 26-5, MPC 34-1 and MPC 10-4 characterization wells. All the values are provided in **Table 1** and summarized in **Table 2**.

[1] EPA (U.S. Environmental Protection Agency). 2013. Geologic Sequestration of Carbon Dioxide, Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators. EPA 816-R-13-005, Washington, D.C.

Table 1: Non-Injection Zones Saline Reservoirs Porosity Data

	MPC 26-5					MPC-34-1					MPC-10-4				
	Depth (feet)		Porosity (fraction)			Depth (feet)		Porosity (fraction)			Depth (feet)		Porosity (fraction)		
	MD	SS	DPHZ	NPHI	PHIE (avg of DPHZ & NPHI)	MD	SS	DPHZ	NPHI	PHIE (avg of DPHZ & NPHI)	MD	SS	DPHZ	NPHI	PHIE (avg of DPHZ & NPHI)
Massive Sand	3598	-3201	0.281	0.307	0.294	3430	-2958	0.284	0.314	0.299	3382	-2907	0.284	0.343	0.3135
	3767	-3370				3626	-3154				3623	-3148			
Dantzler	3820	-3423	0.303	0.346	0.3245	3650	-3178	0.33	0.377	0.3535	3644	-3169	0.291	0.363	0.327
	3954	-3557				3754	-3282				3701	-3226			
Washita-Fredericksburg (Big Fred)	4278	-3881	0.292	0.312	0.302	4148.2	-3676.2	0.274	0.311	0.2925	3985.3	-3510.3	0.268	0.311	0.2895
	4408	-4011				4222	-3750				4133	-3658			
	4413	-4016	0.219	0.271	0.245	4237	-3765	0.249	0.299	0.274	4143	-3668	0.233	0.278	0.2555
	4478	-4081				4428	-3956				4261	-3786			
	4485	-4088	0.255	0.29	0.2725	4466	-3994	0.249	0.29	0.2695	4288	-3813	0.236	0.293	0.2645
	4564	-4167				4485	-4013				4301	-3826			
	4578	-4181	0.278	0.309	0.2935	4498	-4026	0.282	0.314	0.298	4318	-3843	0.251	0.281	0.266
	4661	-4264				4536	-4064				4339	-3864			
	4666	-4269	0.279	0.322	0.3005	4543	-4071	0.207	0.295	0.251	4342	-3867	0.25	0.281	0.2655
	4696	-4299				4560	-4088				4367	-3892			
	4729	-4332	0.242	0.291	0.2665	4602	-4130	0.198	0.293	0.2455	4373	-3898	0.285	0.356	0.3205
	4753	-4356				4612	-4140				4401	-3926			
	4777	-4380	0.279	0.334	0.3065	4704	-4232	0.24	0.321	0.2805	4461	-3986	0.282	0.322	0.302
	4803	-4406				4733	-4261				4507	-4032			
	4811	-4414	0.207	0.274	0.2405	4746	-4274	0.248	0.317	0.2825	4529	-4054	0.176	0.3	0.238
	4883	-4486				4782	-4310				4545	-4070			

Table 2: Non-Injection Zones Saline Reservoirs Porosity Best Estimates Summary

Hydrogeologic Unit	Porosity (fraction)[1]			
	MPC 26-5	MPC 34-1	MPC 10-4	Average
Massive Sand	0.29	0.30	0.31	0.30
Dantzler	0.32	0.35	0.33	0.33
Big Fred	0.28	0.27	0.27	0.27

Injection-Zone Porosity

Porosity values in the Paluxy were derived from an average of the neutron porosity and density porosity logs at the MPC 19-1 well. The log is shown on **Figure 1**. For a more detailed resolution of the modeled CO_2 plume, each of the four Paluxy zones was further sub-divided into five layers of equivalent thickness. The corresponding porosity values are summarized in **Table 3** for all sub-layers of the within the Paluxy Formation.

[1] Mean net sandstone porosity (average of density and neutron porosity)

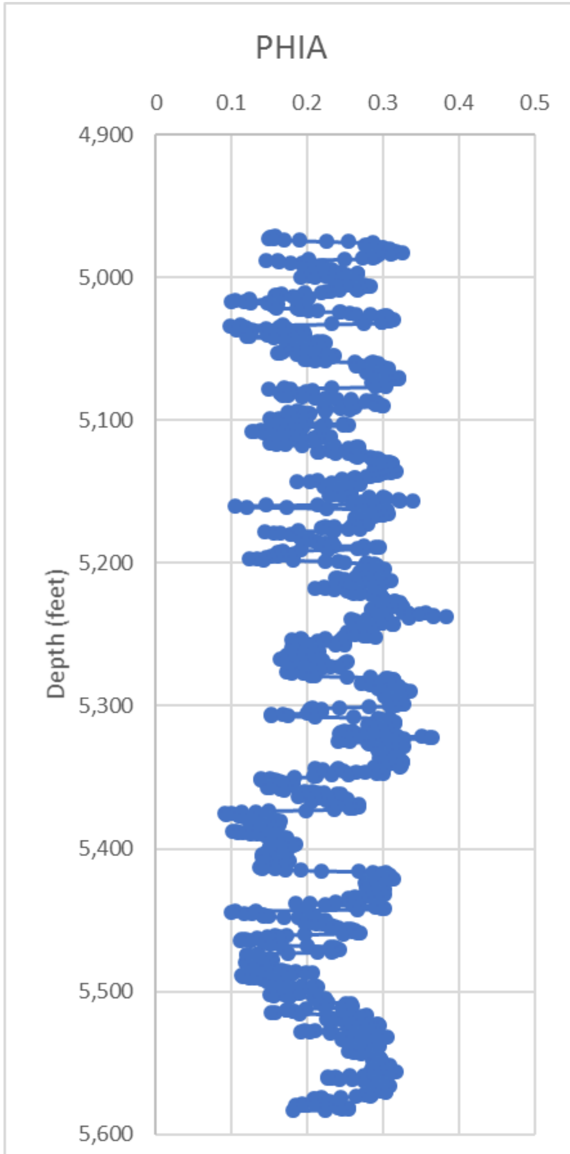

Figure 1: MPC 19-1 Paluxy Average Porosity

Table 3: Injection Zone Porosity Summary

Hydrogeologic Unit	Average Log Porosity (fraction)[1]				
	Sublayer 1	Sublayer 2	Sublayer 3	Sublayer 4	Sublayer 5
Paluxy Zone 4	0.252	0.206	0.255	0.259	0.221
Paluxy Zone 3	0.285	0.269	0.231	0.280	0.298
Paluxy Zone 2	0.212	0.159	0.196	0.243	0.193
Paluxy Zone 1	0.153	0.204	0.260	0.287	0.257

[1] Mean net sandstone porosity (average of density and neutron porosity)

Baffle Porosity

Core was recovered from well MPC 10-4 and routine core analysis (RCA) was performed on mudstones in the Paluxy Formation as well as the Tuscaloosa Marine Shale. Porosity determined through RCA range from 4.2-14.7% for mudstones within the Paluxy Formation, while Tuscaloosa Marine Shale porosity values ranges from 21.2-35.9%. However, these reported porosity values are not consistent with observations of the mudstone from Scanning Electron Microscopy (SEM) images, which indicated significant destressing and desiccation of the rock samples as a result of core retrieval, preparation, and storage. In contrast, porosity measurements of fresh rock cuttings and fresh core analysis indicates porosity values on the order of 2-4%. In light of the changes that occur to rock samples during coring procedures, an average porosity of 10% was applied to the mudstone intervals (non-sand) throughout the storage zone.

A.1.b *Permeability*

Permeability is the ability of a rock to transmit fluid, within its pore structure. A porosity-permeability cross-plot was generated for each rock formation based on various available data and is detailed below. It is to be noted that the horizontal permeability in each flow unit is assumed to be isotropic.

Non-Injection Zone Saline Reservoirs Permeability

This section includes permeability information for all the sandstone formations other than the Paluxy Formation. For the Massive Sand (Tuscaloosa Formation), porosity and permeability data were available from:

- Elemental Log Analysis (ELAN) taken at the MPC 10-4,
- Plant Daniel core (MPC 11-1 well, core #3),
- Kemper water well (2008),
- SECARB Region dataset[1].

[1] Riestenberg, D., & Gray, K. (2011). *Final Report on Lower & Upper Cretaceous Characterization* (No. DOE-SSEB-42590-110). Southern States Energy Board, Peachtree Corners, GA (United States).

After careful review, it was decided not to use the Kemper water well data due to unrealistically high permeability values (about 11 Darcies). A similar decision was made to not use the SECARB Region dataset as it is an assortment of Massive Sand permeability values across variable depositional environments were reported as field wide averages. In addition, the ELAN permeability values for intervals that were greater than 50% shale (log gamma ray values > 100 API) and porosities above 35.5% were not considered. Standard data fits such as power and exponential fits were selected for porosity-permeability cross-plots. For the Massive Sand, the power fit yielded a higher correlation coefficient, R^2, compared to the exponential fit. The porosity-permeability cross-plot for the Massive Sand is shown on **Figure 2**.

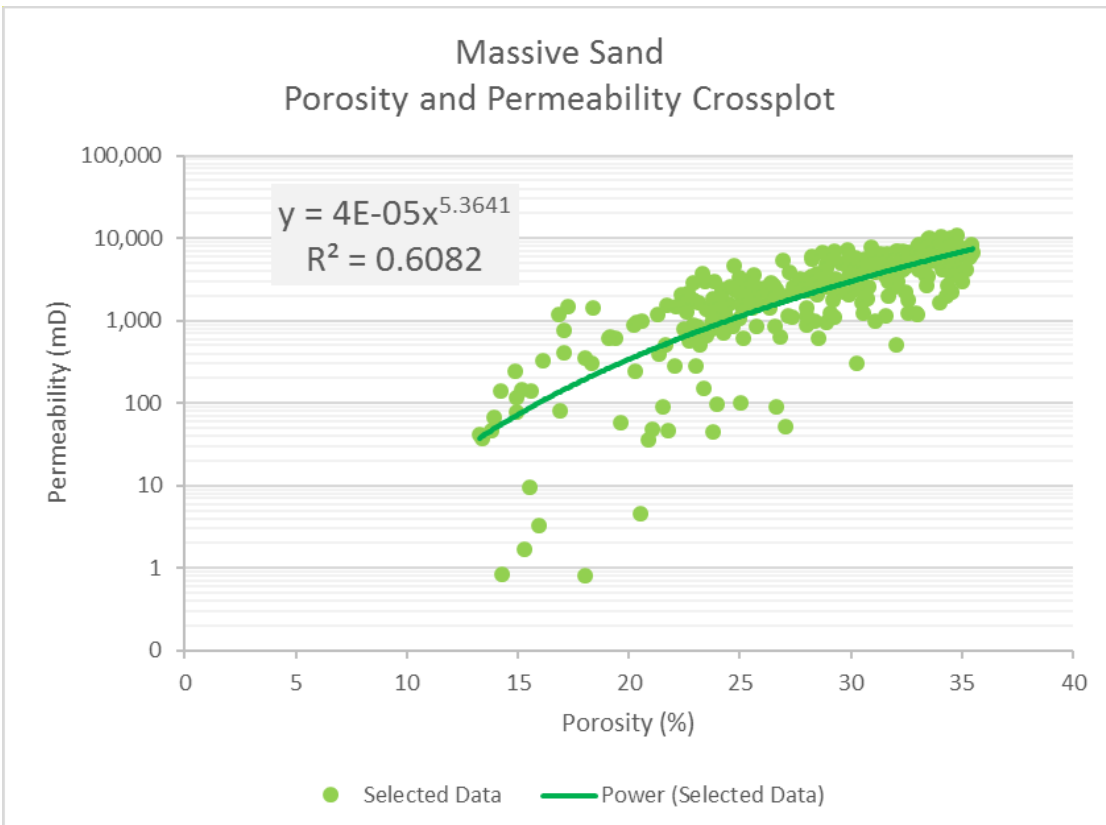

Figure 2: Massive Sand Porosity-Permeability Cross-plot

For the Dantzler Formation, only data from the ELAN log was used. Some log intervals were discarded including those with a high degree of washout (porosity data over 35.5%) and intervals identified as having high chert content. The final porosity-permeability cross-plot for the Dantzler Formation (power fit) is provided on **Figure 3**.

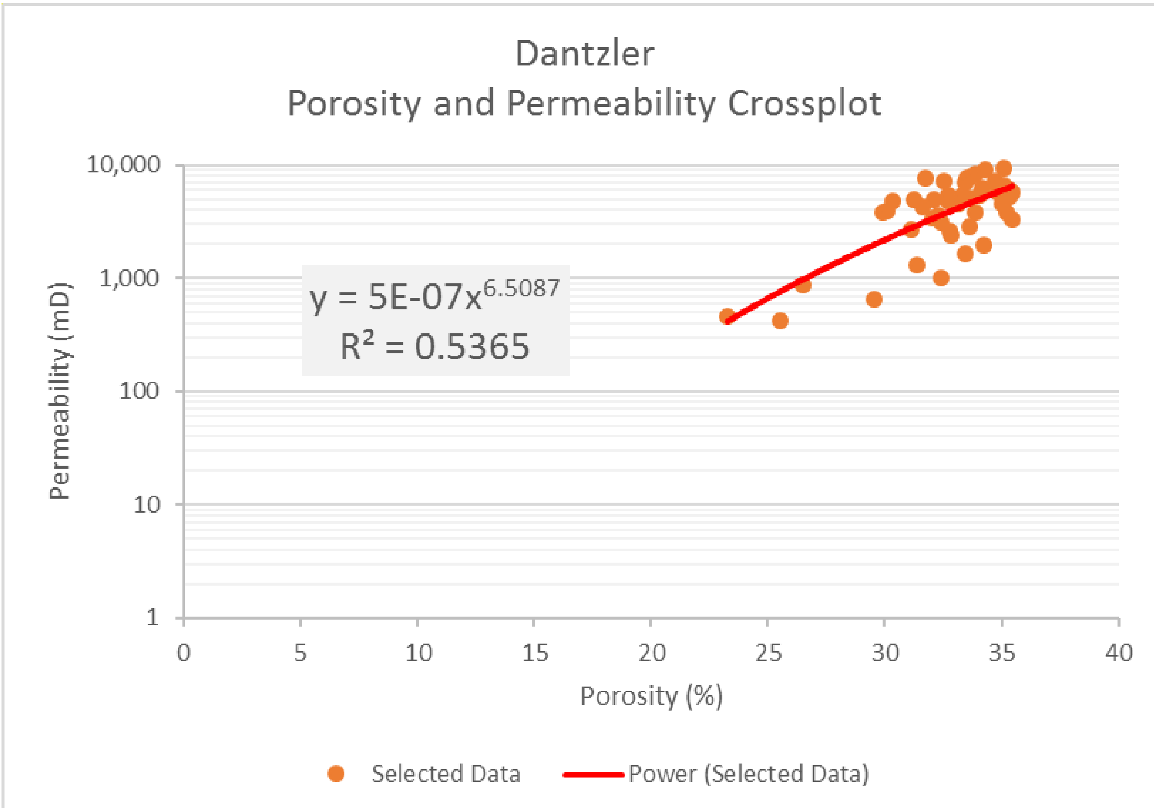

Figure 3: Dantzler Formation Porosity Permeability Cross-plot

For the Big Fred sandstone (Washita Fredericksburg interval), porosity and permeability data was available from ELAN (with porosity cutoff at 35.5% to avoid washed out intervals, shale cutoff at greater than 50%, and borehole radius from the six-arm Caliper Logging Tool HCAL cutoff at 13 inches) as well as core data from the MPC 34-1 well (values with water saturations of >105% are indicative of high clay contents and were dropped as they are not representative of the Big Fred sands). The resulting porosity permeability cross-plot is shown on **Figure 4**.

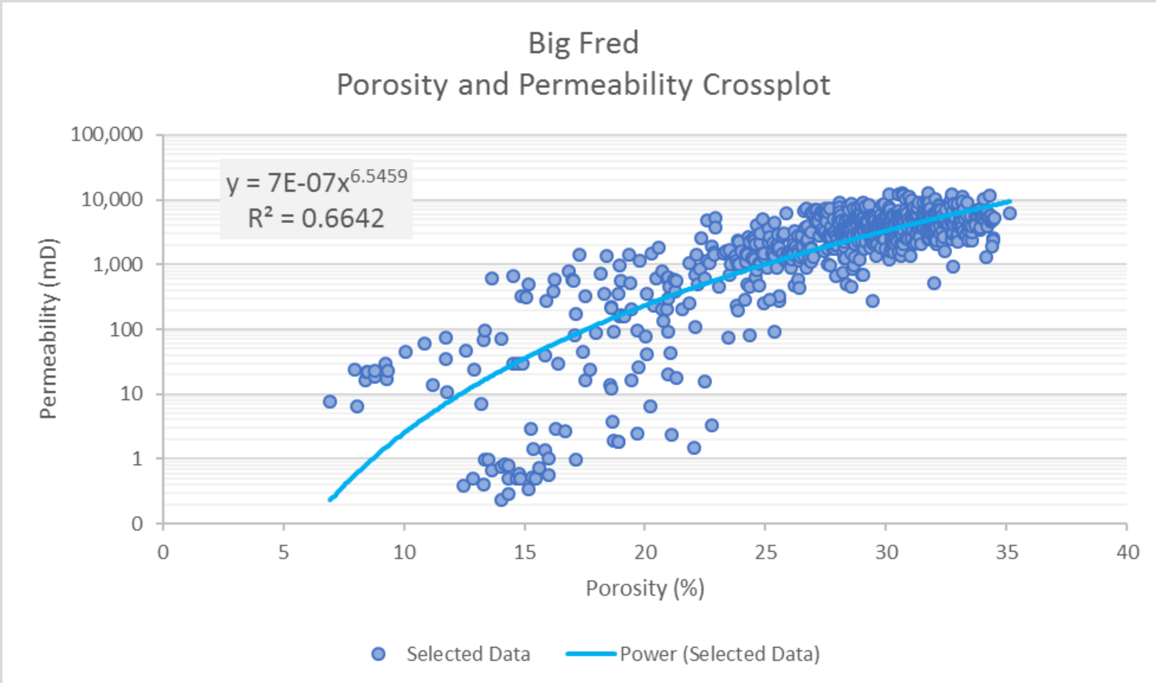

Figure 4: Big Fred Formation Porosity Permeability Cross-plot

After the cross-plots were generated for each formation, the resulting correlation was used to compute the permeability corresponding to the mean net sandstone porosity for each of the three Phase II characterization wells. The average reservoir permeability values for each well were then averaged to generate one value for each formation. These are summarized in **Table 4** below.

Table 4: Kemper County Storage Complex Non-Injection Sandstones' Permeability Estimates

Hydrogeologic Unit	Horizontal Permeability (mD)			
	MPC 26-5	MPC 10-4	MPC 34-1	Average
Massive Sand	2,796	3,998	3,353	3,347
Dantzler	3,130	3,824	5,608	4,064
Big Fred	1,486	1,171	1,171	1,268

Injection Zone Permeability

For the Paluxy sandstone, porosity and permeability data were available from the cores taken at the MPC 10-4 well as well as two Paluxy sandstone core plugs from the MPC 19-1 well. The values from these datasets were used to generate the cross-plot shown on **Figure 5** and establish the porosity-permeability relationship for the Paluxy Formation.

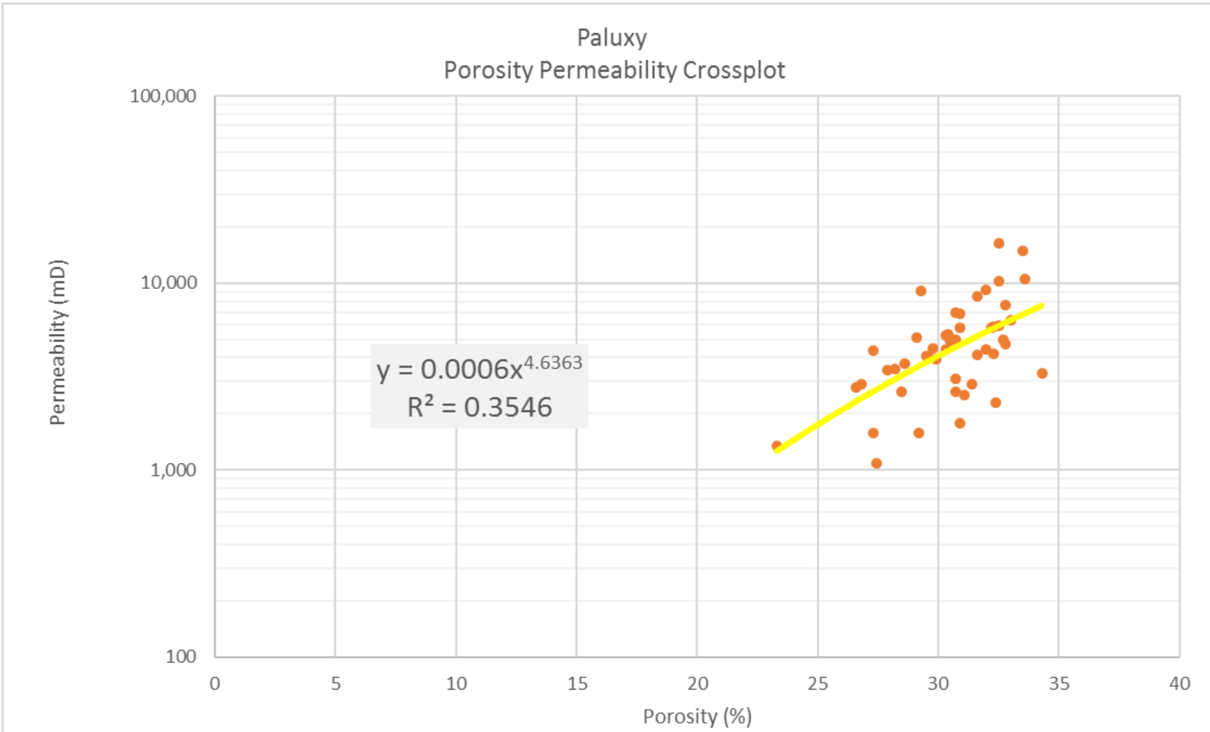

Figure 5: Paluxy Sandstone Porosity Permeability Cross-plot

After the cross-plots were generated, the resulting correlations were used to compute the permeability corresponding to the average porosity for each sublayer of the four Paluxy zones. These permeability values are summarized in **Table 5** below.

Table 5: Injection Zone (Paluxy) Average Horizontal Permeability Estimates

Hydrogeologic Unit	Horizontal Permeability (mD)				
	Sublayer 1	Sublayer 2	Sublayer 3	Sublayer 4	Sublayer 5
Paluxy Zone 4	1,874	738	1,999	2,150	1,018
Paluxy Zone 3	3,337	2,559	1,255	3,066	4,120
Paluxy Zone 2	855	226	594	1,595	545
Paluxy Zone 1	186	714	2,186	3,425	2,055

Figure 6 shows the four generated porosity permeability cross-plots on the same graph.

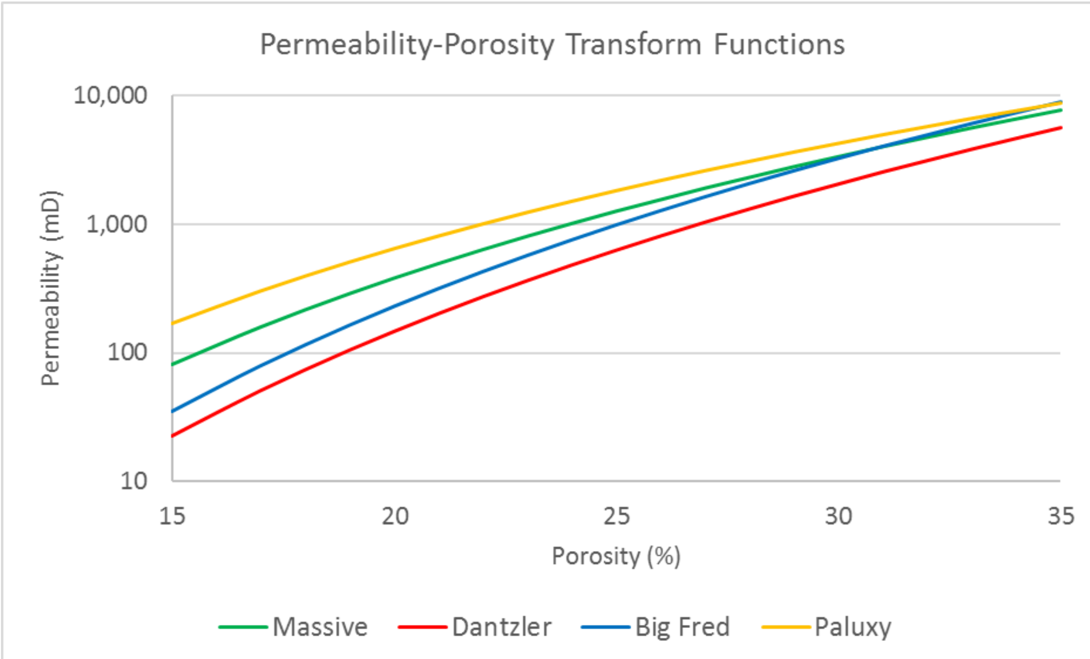

Figure 6: Kemper Sandstones' Porosity Permeability Cross-plot

Baffle Permeability

Pressure decay permeability, also known as pulse decay permeability (PDP), analysis is typically used to measure the permeability of very low permeability rocks, such as mudstones[1]. A pressure decay curve is generated from a mudstone sample that includes a hyperbolic segment, an exponential decay segment, and a pseudo steady-state segment. The hyperbolic segment reflects the filling of fractures and large pores. On the other hand, the exponential decay segment reflects filling of mesopores, micropores, and nanopores. The pseudo steady-state segment reflects insufficient pressure changes late in the analysis which do not provide information on permeability.

Three samples from the MPC 26-5 well, two from the Tuscaloosa Marine Shale and one from the Paluxy Formation, provided high-resolution hyperbolic and exponential pressure decay segments that were used to determine permeability of the mudstones (Pashin et al., 2020)[2]. Hyperbolic segment curve results range from 34.4 nD to 197.4 nD,

[1] Achang, Mercy & Pashin, Jack & Cui, Albert. (2017). The influence of particle size, microfractures, and pressure decay on measuring the permeability of crushed shale samples. International Journal of Coal Geology.

[2] Pashin, J., Achang, M., Martin, S., Urban, S., Wethington, C. (2020). Commercial Scale CO2 Injection and Optimization of Storage Capacity in the Southeastern United States (Project ECO2S, Kemper County Energy Facility, Mississippi). Final Technical Report.

while the exponential segments range from 12.4 nD to 64.4 nD. In contrast, the results from the RCA on the Paluxy Formation range from 0.54 to 38.10 mD. The RCA permeability measurements were likely affected by the desiccation of the mudrock samples which are dried at a temperature of 180°F. Pulse decay permeability measurements were also conducted by a commercial laboratory on shale samples cut from whole-core from the Washita-Fredericksburg formation at well MPC 01-1. The PDP measurements range from 65 nD to 0.491 mD. Overall, a permeability of 50 nD was applied to the confining units within the storage zone.

Vertical Permeability

Vertical permeability at the Kemper County Storage Complex is unknown. A vertical permeability anisotropy (k_v/k_h) of 0.1 was used to compute the vertical permeability from the horizontal permeability. This ratio will be varied in the parametric study to evaluate its impact on the AoR which is discussed in more detail in the *Post-Injection Site Care Plan*.

A.1.c *Relative Permeability*

Sandstones' Relative Permeability

Steady-state brine/CO_2 relative permeability measurements were carried out on Paluxy samples by Piri Technologies at the University of Wyoming [1]. The experiments were done on a composite core sample which was assembled using three core plugs obtained from a cross-bedded, whole core sandstone. Laboratory-grade CO_2 and synthetic reservoir brine were used as the fluid phases. The resulting relative permeability curves are displayed on **Figure 7**. However, these curves were not implemented in the model because of the assumption in the interpretation that brine is in the wetting phase and the supercritical or liquid CO_2 is the non-wetting phase. The fact that the CO_2 is soluble into the brine is not taken into consideration, and this could alter the wettability of the pore system.

[1] Akbarabadi, Arshadi, & Khishvand. Steady-state CO2/Brine Relative Permeability Measurements. Technical Service Report PTSP2018-105 – CONFIDENTIAL, 2019.

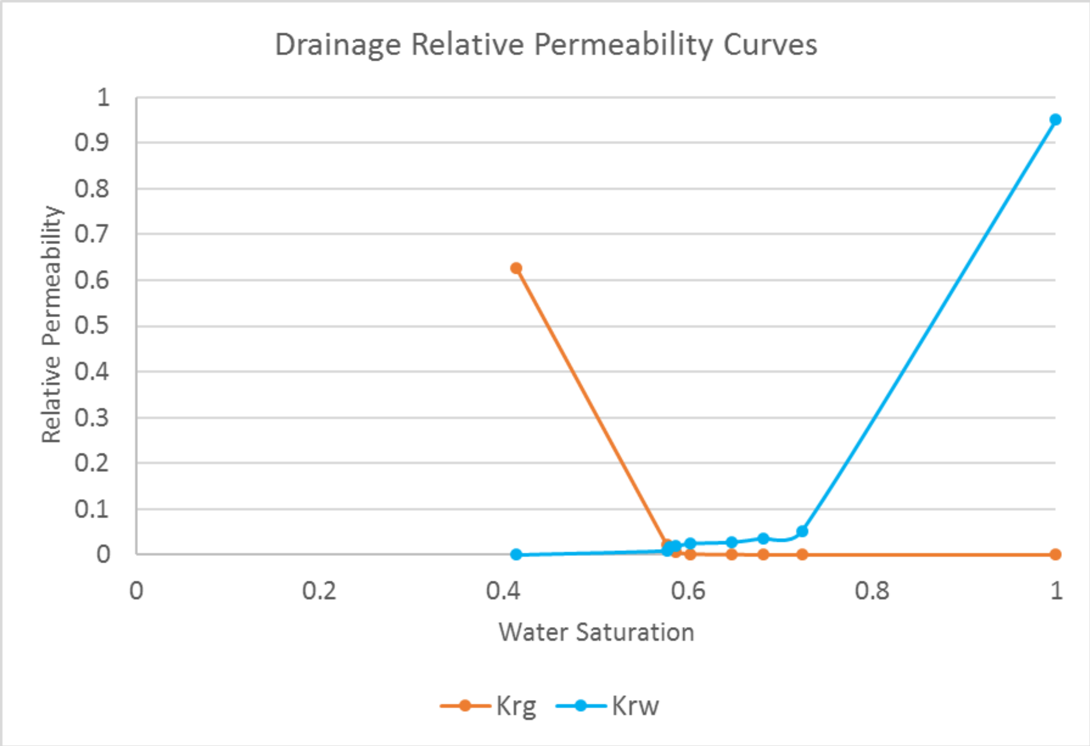

Figure 7: Experimental Drainage Relative Permeability Curves

In addition to the relative permeability curves described above, ARI had previously developed and calibrated a simulation model for the SECARB Anthropogenic Test site at Citronelle, Alabama where CO_2 was injected and stored in the Paluxy Formation[1]. This model consisted of relative permeability curves that matched the historical CO_2 injection pressure and CO_2 breakthrough response, which were monitored at multiple nearby well locations.

[1] Koperna, G.J., Carpenter, S.M., Petrusak, R., Trautz, R., Rhudy, R., and R. Esposito, 12th International Conference on Greenhouse Gas Control Technologies, GHGT-12, Project Assessment and Evaluation of the Area of Review (AoR) at the Citronelle SECARB Phase III Site, Alabama USA, Energy Procedia, Volume 63, 2014, Pages 5971-5985, ISSN 1876-6102, http://dx.doi.org/10.1016/j.egypro.2014.11.632.

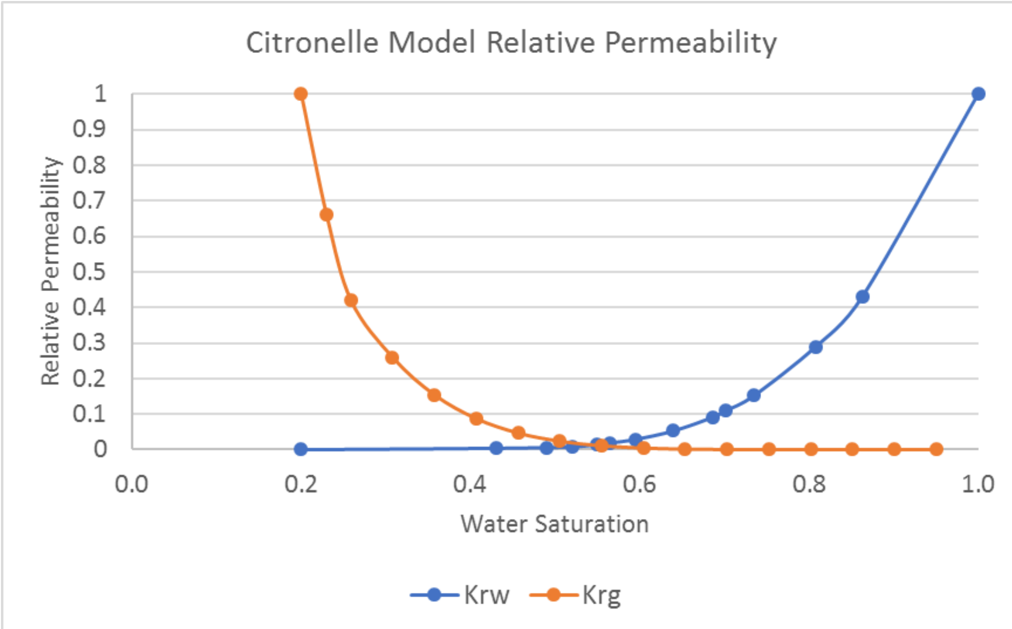

Figure 8: Citronelle Model Relative Permeability Curves

This relative permeability data set (**Figure 8**) was initially applied to all sandstone formations. Based on literature, the CO_2 relative permeability at irreducible water saturation (Krgmax) decreased from 1 to 0.65. The lower endpoint of CO_2 relative permeability is in line with values in the literature for high permeability formations. Bachu (2011)[1] showed the results of relative permeability measurements from 22 core samples from western Canada. They categorized these samples into five groups based on the rock permeability and concluded that for very high permeabilities (greater than 500 mD), the endpoint CO_2 relative permeability was 0.249, **Table 6**.

[1] Bachu, Stefan. 2011. Drainage and Imbibition CO_2/Brine Relative Permeability Curves at In-situ Conditions for Sandstone Formations in Western Canada. GHGT 11, Kyoto, Japan.

Table 6: Findings on KrgMax from Bachu's Study

Rock Group	Permeability (mD)	Median Pore	kr $_{CO2}$ @ Irreducible Brine Saturation	Irreducible S_b	Corey Parameter m for brine	Corey Parameter n for CO_2
Very low *k*	*k*<0.1	0.555	0.394	0.370	1.43	3.99
Low *k*	0.1<*k*10	1.123	0.380	0.495	2.01	2.71
Mid *k*	10<*k*<100	8.628	0.201	0.495	1.81	2.55
High *k*	100<*k*<500	15.346	0.176	0.545	2.12	4.73
Very high *k*	*k*>500	20.300	0.249	0.545	1.39	4.78

(Source: Bachu, 2011)

Krevor et. al. (2012)[1] report higher endpoint values for CO_2 relative permeability of between 0.5 and 0.95. As such, it was decided to lower the maximum gas relative permeability from 1.0 to 0.65. This parameter will be part of the sensitivity analysis to understand its impact on injectivity and the size of the CO_2 plume, which is discussed in the *Post Injection Site Care Plan*. The modeled set of relative permeability curves from the characterization of the Kemper County Storage Complex is shown on **Figure 9**.

[1] Krevor, S. Pini, R. Zuo, L. Benson, S. 2012. Relative Permeability and Trapping of CO2 and Water in Sandstone Rocks at Reservoir Conditions. Water Resources Research, Volume 48, W02532.

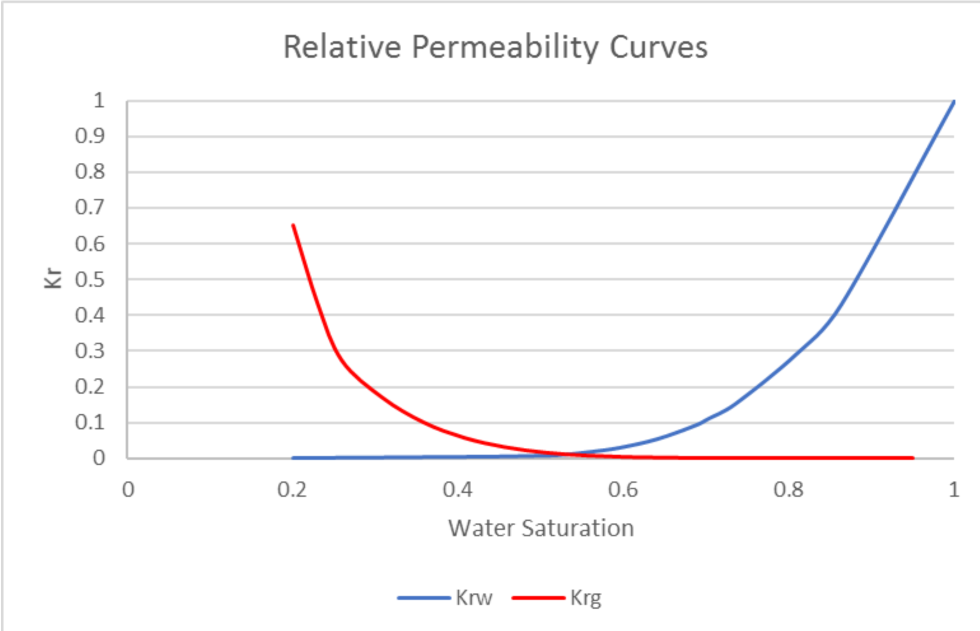

Figure 9: Kemper Model Sandstones' Relative Permeability Curves

Confining Units' Relative Permeability

Relative permeability data were not available for the confining units at the Kemper County Storage Complex. The relative permeability curves used were from the Calmar formation of the Alberta Basin, reported by Bennion and Bachu (2007)[1]. The Calmar formation was chosen as a proxy due to its properties (salinity and pressure gradient for example) being close to the properties at the Kemper County Storage Complex. The set of curves represent a very low permeability shale rock with high irreducible water saturation and a very low gas relative permeability. Relative permeability data are available in **Table 7** and illustrated on **Figure 10**.

[1] Bennion, B. D., & Bachu, S. (2007). Permeability and relative permeability measurements at reservoir conditions for CO2-Water systems in ultra low permeability confining caprocks. Society of Petroleum Engineers.

Table 7: Kemper County Storage Complex Shale Relative Permeability's Best Estimate

CO_2 Saturation	Water Saturation	Krg	Krw
0.362	0.638	0.1871	0.0000
0.344	0.656	0.1751	0.0010
0.326	0.674	0.1632	0.0041
0.308	0.692	0.1515	0.0101
0.290	0.710	0.1401	0.0197
0.272	0.728	0.1288	0.0334
0.254	0.746	0.1178	0.0518
0.236	0.764	0.1070	0.0752
0.217	0.783	0.0965	0.1042
0.199	0.801	0.0862	0.1390
0.181	0.819	0.0762	0.1800
0.163	0.837	0.0664	0.2276
0.145	0.855	0.0570	0.2820
0.127	0.873	0.0480	0.3437
0.109	0.891	0.0393	0.4128
0.091	0.909	0.0310	0.4897
0.073	0.927	0.0232	0.5747
0.054	0.946	0.0160	0.6679
0.036	0.964	0.0095	0.7697
0.018	0.982	0.0039	0.8803
0.000	1.000	0.000	1.000

(Source: Bennion and Bachu, 2007)

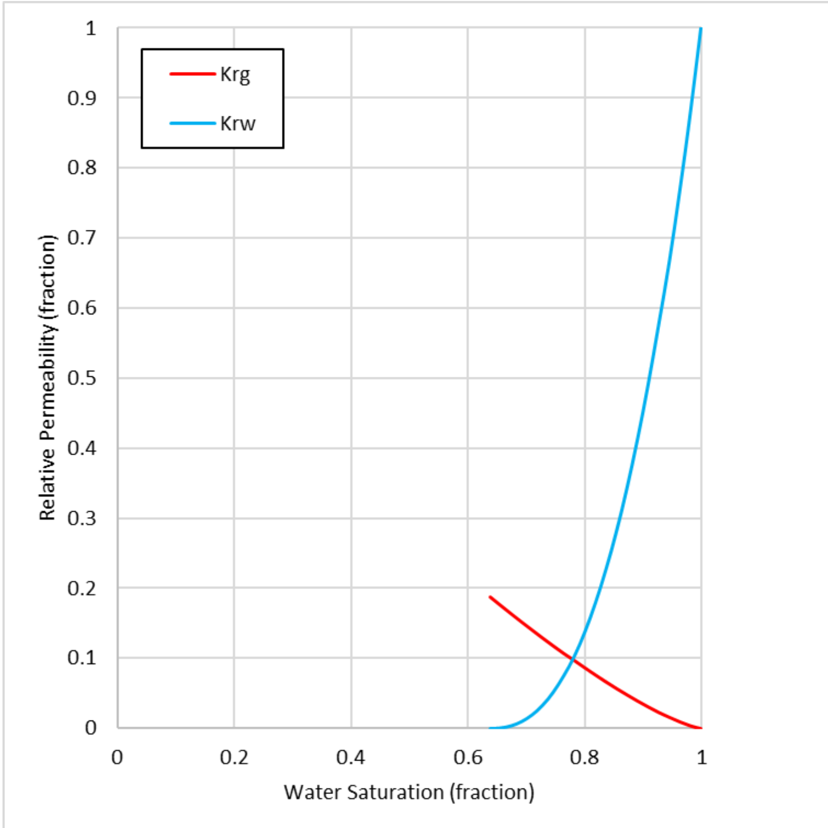

Figure 10: Kemper County Storage Complex Confining Units' Best Estimate of Relative Permeability

A.1.d *Capillary Pressure Relationships*

Capillary pressure is the pressure difference across the interface between two immiscible fluids (e.g., CO_2 and water). The capillary entry pressure is the minimum pressure required for an immiscible non-wetting fluid (i.e., CO_2) to overcome capillary and interfacial forces and enter pore space containing the wetting fluid (i.e., saline formation water) (EPA 2013)[1]. Capillary pressure relationships are typically reported as a function of the wetting phase saturation using capillary pressure curves generated by laboratory

[1] EPA (U.S. Environmental Protection Agency). 2013. Geologic Sequestration of Carbon Dioxide, Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators. EPA 816-R-13-005, Washington, D.C.

testing. Mathematical models have also been developed to represent these relationships (e.g., van Genuchten 1980[1]; EPA 2013[1]).

Sandstones' Capillary Pressure

Mercury Injection Capillary pressure data was collected from seven sandstone core samples from the Paluxy Formation at the MPC 10-4 well and analyzed. The Swanson permeability of these samples ranges from 751 to over 5,800 mD. These curves (**Figure 11**) are from the highest permeability sandstone of the Paluxy Formation showing very low irreducible water saturation of 3 to 6%. However, these low irreducible water saturations may not be a true representative irreducible water saturation of the entire Paluxy, including lower porosity intervals. As such, the decision was made to use correlations to generate a capillary pressure curve from the relative permeability curves.

[1] Van Genuchten, M.T. (1980) A Closed Form Equation for Predicting the Hydraulic Conductivity of Unsaturated Soils. Soil Science Society of America Journal, 44, 892-898.

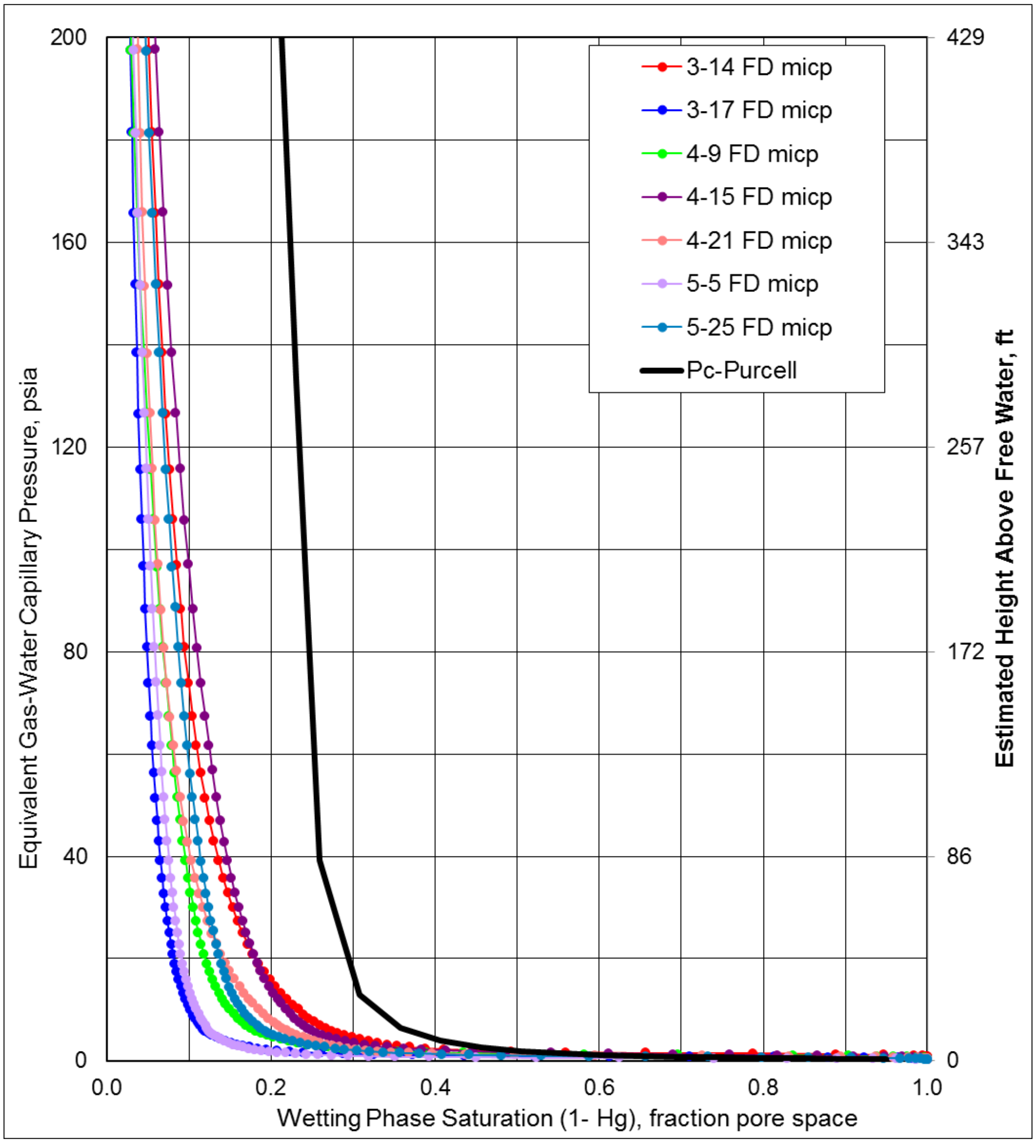

Figure 11: MPC10-4 Capillary Pressure Curves

Li et. al. (2006[1]) compared different methods to calculate relative permeability from capillary pressure data (and vice versa) in consolidated water-wet rocks. Li et. al. suggests the Purcell model to be used as it best fits the wetting phase relative permeability curve (**Equation 1**):

$$K_{rw} = (S_w^*)^{\frac{2+\lambda}{\lambda}} \tag{1}$$

where λ is the pore size distribution index and S_w^* is the normalized wetting-phase saturation. In the absence of capillary pressure data, the parameter λ becomes a tuning parameter to fit the Purcell equation to the existing wetting-phase relative permeability curve. The normalized saturation can be obtained from the following, **Equation 2**:

$$S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr}} \tag{1}$$

where S_{wr} is the irreducible wetting-phase saturation and S_w is the wetting-phase saturation from the relative permeability curve table.

From the fitting process, the pore size distribution index can be obtained, which can then be used in the Brooks-Corey equation (**Equation 3**) to calculate the capillary pressure for a range of the wetting-phase saturations.

$$P_c = P_e (S_w^*)^{-\frac{1}{\lambda}} \tag{2}$$

The entry capillary pressure (P_e) in the equation was estimated to be around 0.34 psi, obtained from the Paluxy core samples' MICP data. The generated capillary pressure curve in shown on **Figure 12** below.

[1] Li, K., and R. N. Horne (2006), Comparison of methods to calculate relative permeability from capillary pressure in consolidated water-wet porous media, Water Resources. Res., 42, W06405, doi:10.1029/2005WR004482.

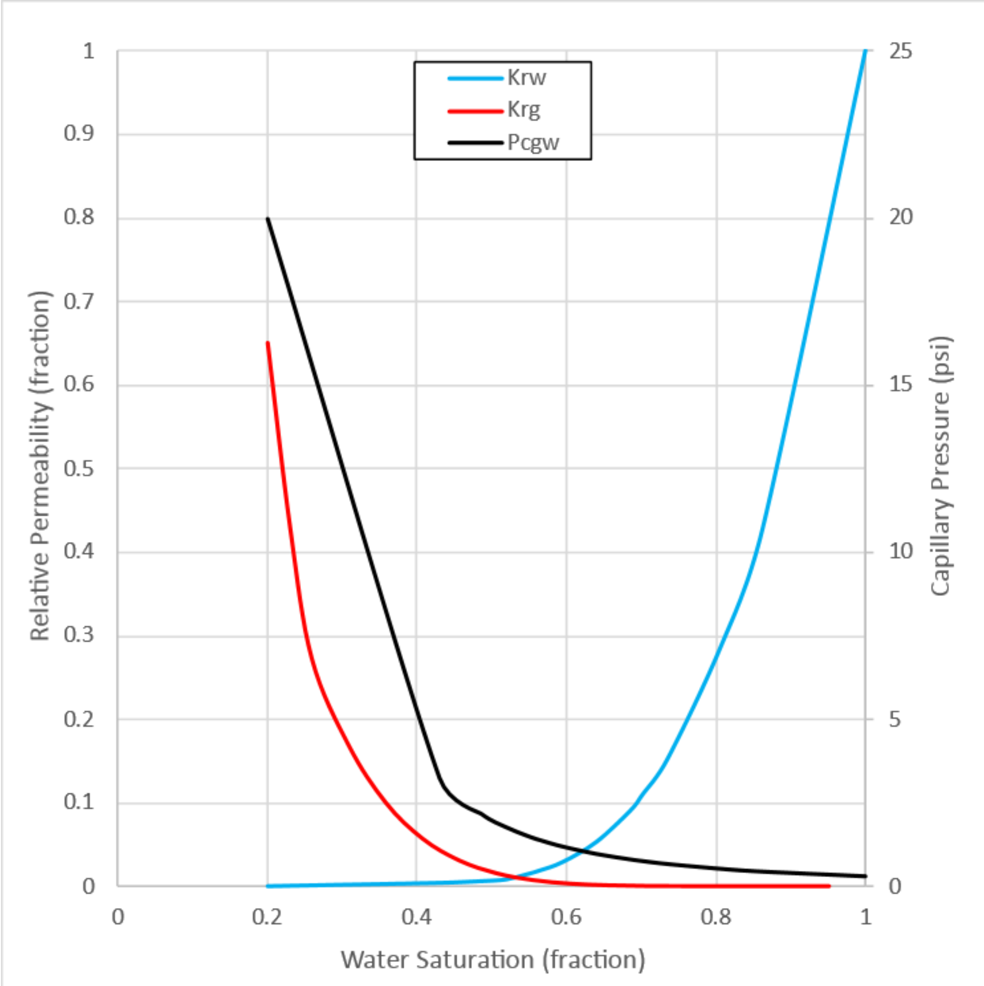

Figure 12: Modeled Drainage Relative Permeability and Capillary Pressure Curves for the Sandstone Layers

Confining Layers' Capillary Pressure

Shale capillary pressure curves show very high entry capillary pressure values (over 700 psi from 23 samples in the Tuscaloosa Marine Shale and 8 in the Lower Tuscaloosa Shale) from Lohr and Hackley, 2018[1]. These high entry capillary pressures mean that the CO_2 pressure in the injection zone needs to exceed these values to enter the 100% brine saturated caprock pores. As a conservative approach, capillary pressures are excluded for the shale layers to allow CO_2 migration into the caprock with the smallest pressure increase. However, because of the very low permeability of the shale layers,

[1] Celeste D. Lohr and Paul C. Hackley (2018), Using mercury injection pressure analyses to estimate sealing capacity of the Tuscaloosa marine shale in Mississippi, USA: Implications for carbon dioxide sequestration, International Journal of Greenhouse Gas Control

CO_2 stays within the Paluxy Formation and does not leak into the Lower Washita-Fredericksburg Shale.

A.1.e *Formation (Pore) Compressibility*

Formation compressibility is a measure of change in rock volume with a change in fluid pressure. Injection-zone formations are subjected to constant external (lithostatic) pressure and internal fluid pressure within the pore spaces. When the internal fluid pressure is reduced (e.g., through oil or gas production), the bulk volume of the rock decreases while the relative volume of the solid rock material (e.g., sand grain or sandstone) increases, effectively reducing the porosity. Rock compressibility data for an injection zone are generally obtained from laboratory measurements on core samples, or where unavailable, estimated from porosity and overburden pressure (EPA 2013)[1].

Pore compressibility data for the Paluxy Formation was estimated using the Hall (1953)[2] correlation (**Equation 4**). The correlation is based on laboratory data and is considered reasonable for normally pressured sandstones. With porosity in the Paluxy varying from 0.153 to 0.298, the corresponding compressibility varies between 3.03E-6 /psi and 4.05E-6 /psi with a weighted average of 3.3E-6 /psi.

$$cf = \left(\frac{1.782}{\emptyset^{0.438}}\right) 10^{-6} \qquad \textbf{(4)}$$

A.1.f *Formation (Fluid) Pressure*

The pressure gradient at the Kemper County Storage Complex is 0.427 psi/ft, or normally pressured, based on seven different measurements that are summarized in **Table 8.**

[1] EPA (U.S. Environmental Protection Agency). 2013. Geologic Sequestration of Carbon Dioxide, Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators. EPA 816-R-13-005, Washington, D.C.

[2] Hall, Howard N., 1953. Compressibility of Reservoir Rocks. J Pet Technol 5 (1953): 17–19. doi: https://doi.org/10.2118/953309-G

Table 8: Reservoir Pressure Gradient Best Estimates

Hydrogeologic Unit	Pressure Gradient (psi/ft)	Source
Tuscaloosa (Massive Sand)	0.436 psia/ft	Water analysis – Kemper County well - 2008
Tuscaloosa (Massive Sand)	0.498 psia/ft	Water analysis – Water well #1 – May 2018
Washita Fredericksburg	0.433 psia/ft	MPC 34-1 Pressure Falloff Test – April 2018
Washita Fredericksburg	0.400 psia/ft	MPC 34-1 Pressure Falloff Test – April 2018
Washita Fredericksburg	0.386 psia/ft	MPC 34-1 Water Sample – April 2018
Paluxy	0.410 psia/ft	MPC10-4 Pressure Falloff Test – June 2019
Paluxy	0.424 psia/ft	MPC 10-4 Water Sample – June 2019

A.1.g *Formation Temperature*

Formation temperatures were reported for different reservoirs at the Water Well No. 1, MPC 34-1, and MPC 10-4 wells during fluid sampling operations conducted from June 2018 through August 2019. Formation pore-fluids were sampled using Core Laboratories™ Positive Displacement Bottom Hole Sampling (PDBHS) Tool from each formation. A reservoir sampling pressure and temperature was recorded at the fluid sampling depth. At Water Well No. 1, the Lower Tuscaloosa was sampled at a depth of 2,841 feet at a pressure of 1,400 psig and temperature of 100 °F. At well MPC 34-1, the Washita-Fredericksburg interval was sampled at 4,470' at a pressure of 1,750 psig and a temperature of 125 °F. At well MPC 10-4, the Paluxy Formation was sampled at a depth of 5,183 feet at a pressure of 2,180 psig and a temperature of 128 °F. The data is summarized in **Table 9** and was included in the model.

Table 9: Kemper County Storage Complex Formation Temperatures Estimates

Hydrogeologic Unit	Sample	Depth (feet)	Temperature (F)	Temperature Gradient (°/100ft)
Lower Tuscaloosa	201801592-01	2,841	100	0.40
Washita Fredericksburg	201801231-05	4,470	125	0.65
Paluxy	201901859-01	5,183	128	0.68

A.1.h *Water Saturation*

Kemper County does not have any oil and gas production, and formations at the Kemper County Storage Complex are fully saturated with water. This is confirmed by the ELAN geophysical well logs taken at the MPC 10-4 well as shown in **Figure 13**, which highlights water saturation in the Massive Sand and Dantzler. Similarly, **Figure 14** corresponds to the Big Fred sandstone, and **Figure 15** for the Paluxy sandstone.

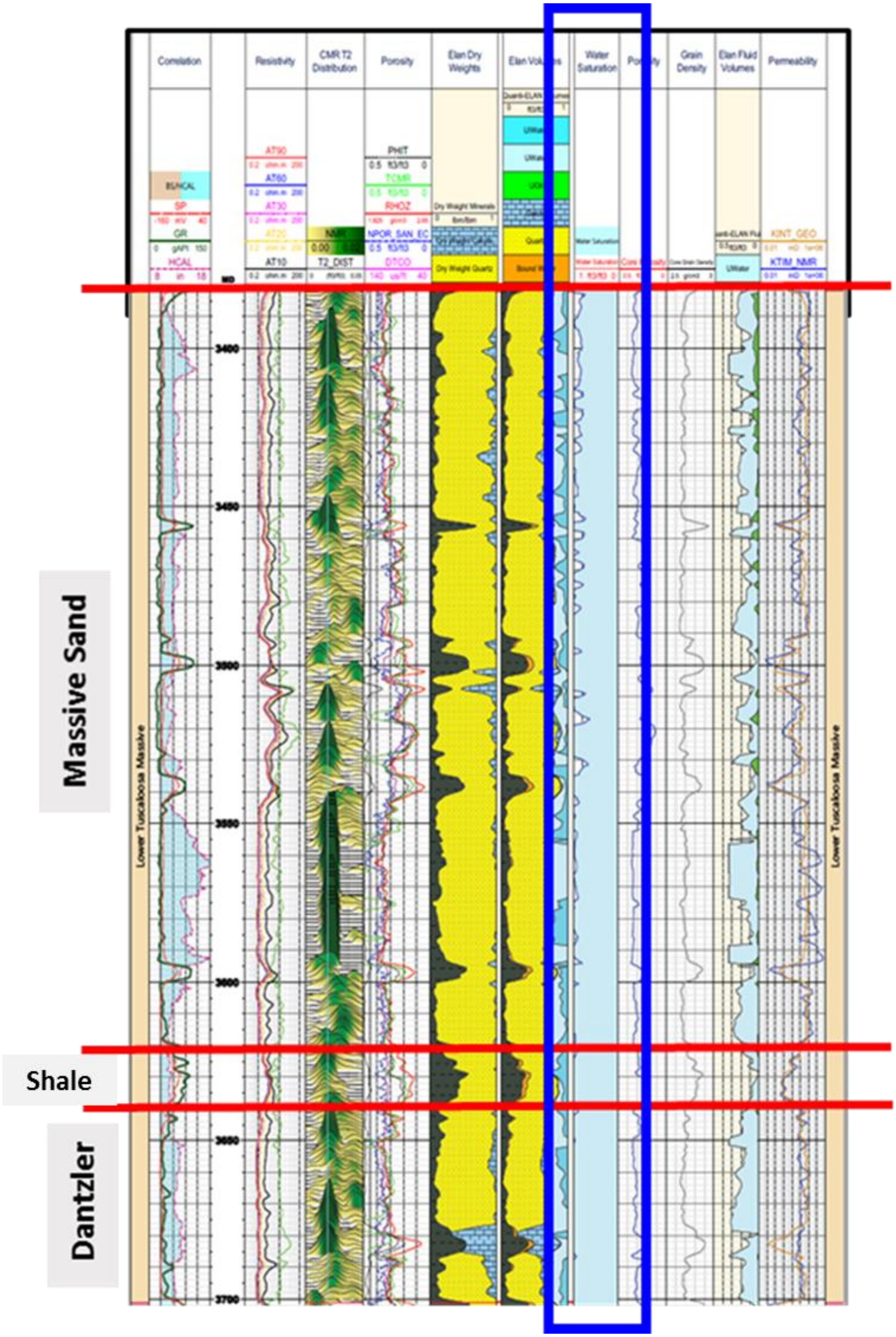

Figure 13: MPC10-4 ELAN – Massive Sand, Shale and Dantzler Water Saturation

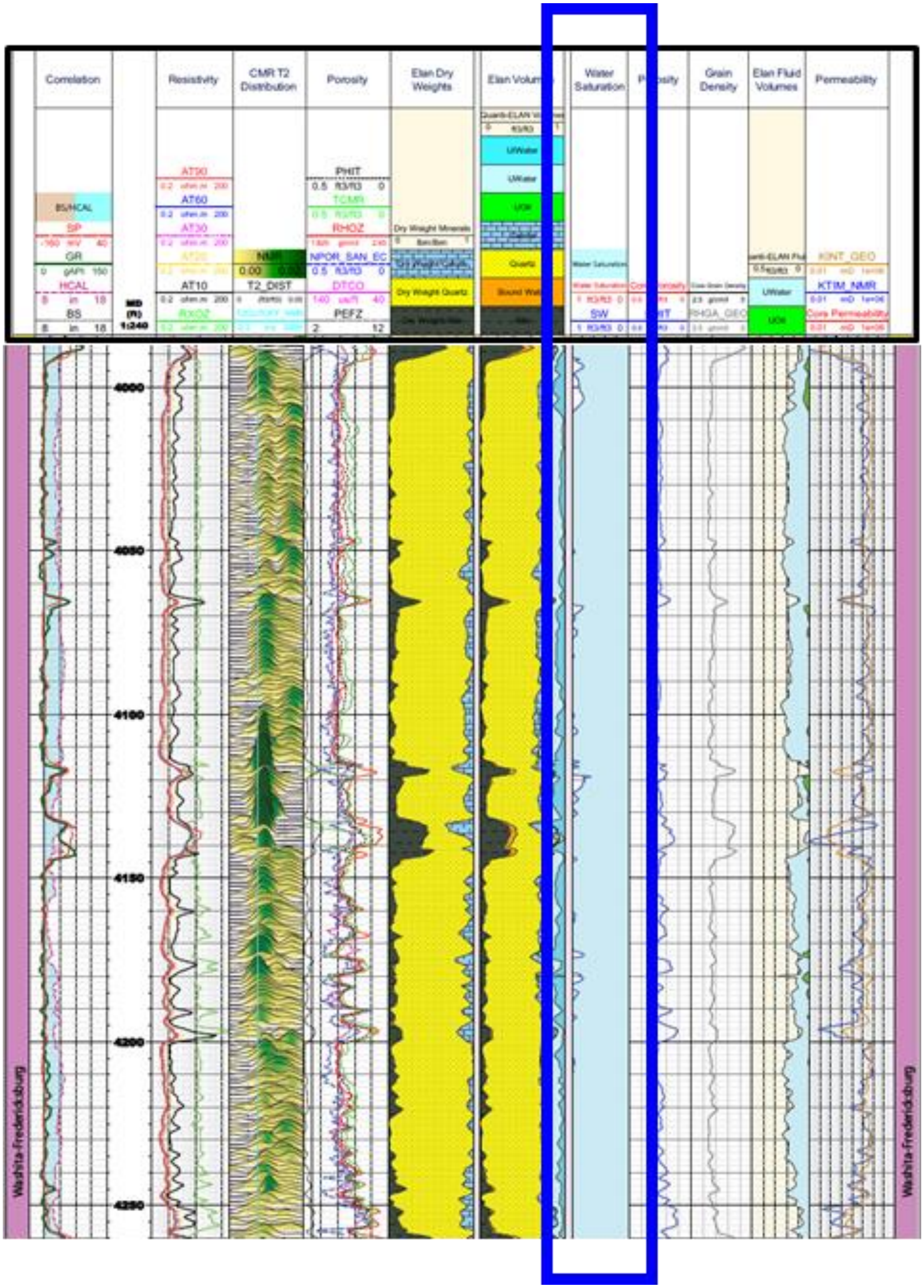

Figure 14: MPC10-4 ELAN – Big Fred Water Saturation

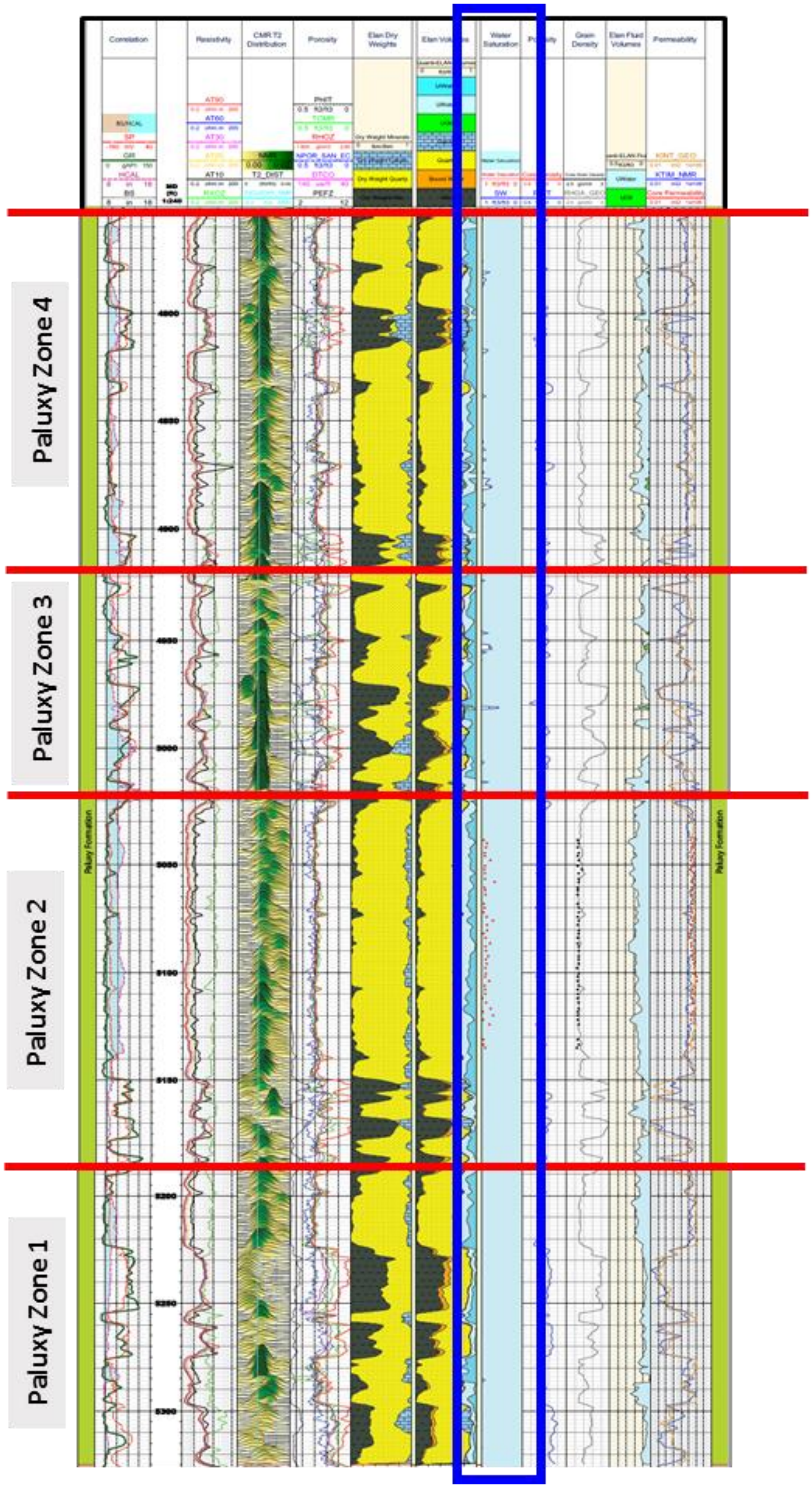

Figure 15: MPC10-4 ELAN – Paluxy Water Saturation

A.1.i *Storativity (Storage Coefficient)*

Storativity is defined as "the volume of water that an aquifer releases from storage per unit surface area of aquifer per unit decline in the component of hydraulic head normal to that surface".[1]

Storativity, or the storage coefficient is calculated from the following equation (Equation 5):

$$S = \rho g h\left(c_w + \emptyset c_f\right) \tag{5}$$

where ρ = fluid density
h = formation thickness
c_w = water compressibility
c_f = formation compressibility
$\emptyset$ = porosity

The storage coefficient for the Paluxy Formation, being a confined aquifer at the top by the Lower Washita-Fredericksburg Shale and at the bottom by the Mooringsport formation, is between 9.7E-4 and 1E-3. These values are consistent with the range of storativity given on Freeze and Cherry (1979)[1] for confined aquifers. The reservoir and fluid properties used in calculating the storage coefficient for the Paluxy Formation are provided in **Table 10**.

Table 10: Reservoir and Fluid Properties Used to Calculate Paluxy Formation's Storage Coefficient

Formation	Depth (ft)	Pressure (psi)	Pressure (MPa)	T (C)	ρ (kg/m³)	c_w (1/MPa)	c_f (1/MPa)	Porosity (frac)	Thickness (m)	Storativity
Paluxy 4	5,053	2,158	14.9	55.3	1,065	4.6E-04	4.8E-04	0.24	164	9.9E-04
Paluxy 3	5,214	2,226	15.4	56.4	1,065	4.6E-04	4.6E-04	0.27	164	1.0E-03
Paluxy 2	5,348	2,284	15.7	57.2	1,065	4.6E-04	5.2E-04	0.20	164	9.7E-04
Paluxy 1	5,484	2,342	16.1	58.1	1,065	4.6E-04	4.9E-04	0.23	164	9.9E-04

[1] R. Allan Freeze, John A. Cherry, 1979, Groundwater, Prentice-Hall, Inc. 604p

A.1.j *Fluid Properties*

Fluid properties such as salinity, density, viscosity, and compressibility from groundwater, and any other fluids that may be present (e.g., CO_2 and hydrocarbons) are important model input parameters (EPA 2011). These properties change significantly relative to depth, temperature, and pressure and are predicted by equations of state used by the model to calculate properties at conditions encountered in the simulation as they change with location and time. The rationale for selection of best estimates for fluid properties follows.

Viscosity

Viscosity is a measure of the resistance of a fluid, which is being deformed by either shear or tensile stress. Lower viscosity fluids (i.e., freshwater) flow more easily than higher viscosity fluids (i.e., saline water). Dynamic viscosity is a function of brine temperature, salinity, and formation pressure. Kestin et al. (1981)[1] found that viscosity increases with higher salinity and formation pressure but also decreases under higher temperature. Viscosity is factored into the simulation model using the Kestin *et al.* (1981)[2] correlation, which computes brine viscosity as a function of pressure, temperature, and salinity.

$$\mu_B = \mu(1+\beta P) \quad \textbf{(6)}$$

Where $\text{Log}(\mu) = A+3.0000867722+C(B+1)$
$A_1 = 3.324*10^{-2}$
$A_2 = 3.624*10^{-3}$
$A_3 = -1.879*10^{-4}$
$B_1 = -3.96*10^{-2}$
$B_2 = 1.02*10^{-2}$
$B_3 = -7.02*10^{-4}$
$A=A_1S+A_2S^2+A_3S^3$
$B=B_1S+B_2S^2+B_3S^3$

[1] Kestin, J. Khalifa, H. Correia, R. 1981. Tables of the Dynamic and Kinematic Viscosity of Aqueous NaCl Solutions in the Temperature Range 20-150C and the Pressure Range 0.1-35MPa. J. Phys. Chem. Ref. Data Vol. 10, No. 1.

$C=1.2378(20-T)-1.303*10^{-3}(20-T)^2+3.06*10^{-6}(20-T)^3+2.55*10^{-8}(20-T)^4/(96+T)$
$\beta = \beta_s*\beta_p+\beta_w$
$\beta_w = -1.297+5.74*10^{-2}T-6.97*10^{-4}T^2+4.47*10^{-6}T^3-1.05*10^{-8}T^4$
$\beta_s = 0.545+2.8*10^{-3}T-\beta_w$
$\beta p = 2.5(S/m_s)-2(S/m_s)^2+0.5(S/m_s)^3$
$m_s = 6.044+2.8*10^{-3}T+3.6*10^{-5}T^2$

where P is pressure in MPa, T is temperature in degrees C, S is the mass fraction of NaCl in the NaCl solution and the viscosity μ_B is in Pa.s. The modeled water viscosity is illustrated on **Figure 16**. At initial conditions, in the area of the injection wells in the Paluxy, the water viscosity ranges approximately from 0.6cp to 0.64cp.

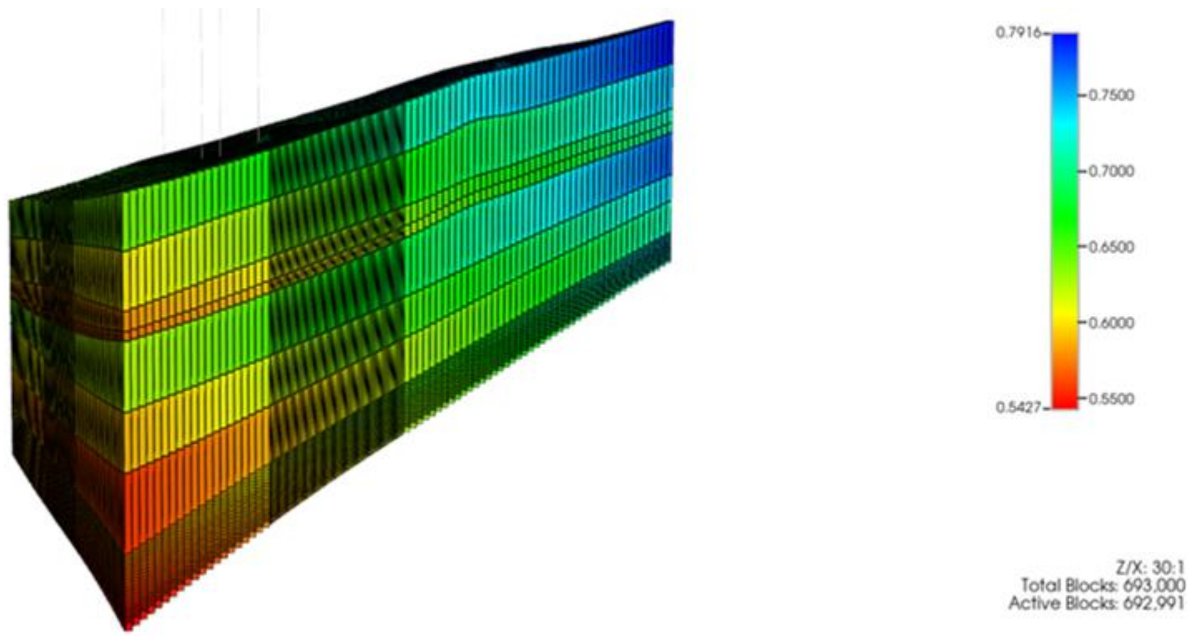

Figure 16: Kemper County Storage Complex Modeled Water Viscosity (Centipoise)

Salinity

Water salinities were reported for different reservoirs at the Water Well No. 1, MPC 34-1, and MPC 10-4 wells during fluid sampling operations conducted from June 2018 through August 2019. Formation pore-fluids were sampled using Core Laboratories™ PDBHS Tool from each formation. At Water Well No. 1, the Lower Tuscaloosa was sampled at a depth of 2,841 feet. The water analysis performed on that sample reported a Total Dissolved Solids (TDS) of 18,791 mg/l or 18,567 ppm. At well MPC 34-1, the Washita-Fredericksburg interval was sampled twice at 4,470 feet. The water analysis performed on these 2 samples reported a TDS of 85,271 mg/l and 86,430 mg/l corresponding to TDS of 80,587 ppm and 81,779 ppm, respectively. At well MPC 10-4, the Paluxy Formation was sampled at a depth of 5,183 feet. The water analysis performed on that sample reported a TDS of 115,531 mg/l or 107,196 ppm. The data is summarized in **Table 11**. In the model, the Lower Tuscaloosa salinity was applied to the Upper Tuscaloosa Shale, the Marine Tuscaloosa Shale, and the Massive and Dantzler sandstones. The Washita Fredericksburg salinity was applied to the Big Fred sandstone and the Upper and Lower Washita Fredericksburg shales. The Paluxy salinity was applied to all layers within the Paluxy as well as the Mooringsport formation.

Table 11: Kemper County Storage Complex Formation Water Salinities

Hydrogeologic Unit	Sample	TDS (mg/l)	TDS (ppm)	Source
Lower Tuscaloosa	201801592-01	18,791	18,567	Water Well No 1 Analysis
Washita Fredericksburg	201801231-05	85,271	80,587	MPC34-1 Water Analysis
Washita Fredericksburg	201801231-06	86,430	81,779	MPC34-1 Water Analysis
Paluxy	201901859-01	115,531	107,196	MPC10-4 Water Analysis

Density

In the absence of actual density data, brine salinity values from **Table 11** were converted to corresponding density (in g/cc) values using **Equation 7**:

$$\rho_w = 1 + TDS*0.695*1e\text{-}6 \qquad \textbf{(7)}$$

With TDS in ppm

The values are summarized in **Table 12**.

Table 12: Kemper County Storage Complex Estimates of Water Density

Hydrogeologic Unit	TDS (ppm)	Density (g/cc)	Temperature (F)	Source
Lower Tuscaloosa	18,567	1.013	100	Water Well No 1 Analysis
Washita Fredericksburg	80,587	1.056	125	MPC34-1 Water Analysis
Washita Fredericksburg	81,779	1.057	125	MPC34-1 Water Analysis
Paluxy	107,196	1.075	128	MPC10-4 Water Analysis

These values are consistent with general correlations of density as a function of TDS and temperature (Gearhart-Owens, 1972)[1], **Figure 17**.

[1] Gearhart-Owens Industries, 1972, GO Log Interpretation Reference Data Handbook: Fort Worth, Gearhart-Owens Industries Inc., 226 p

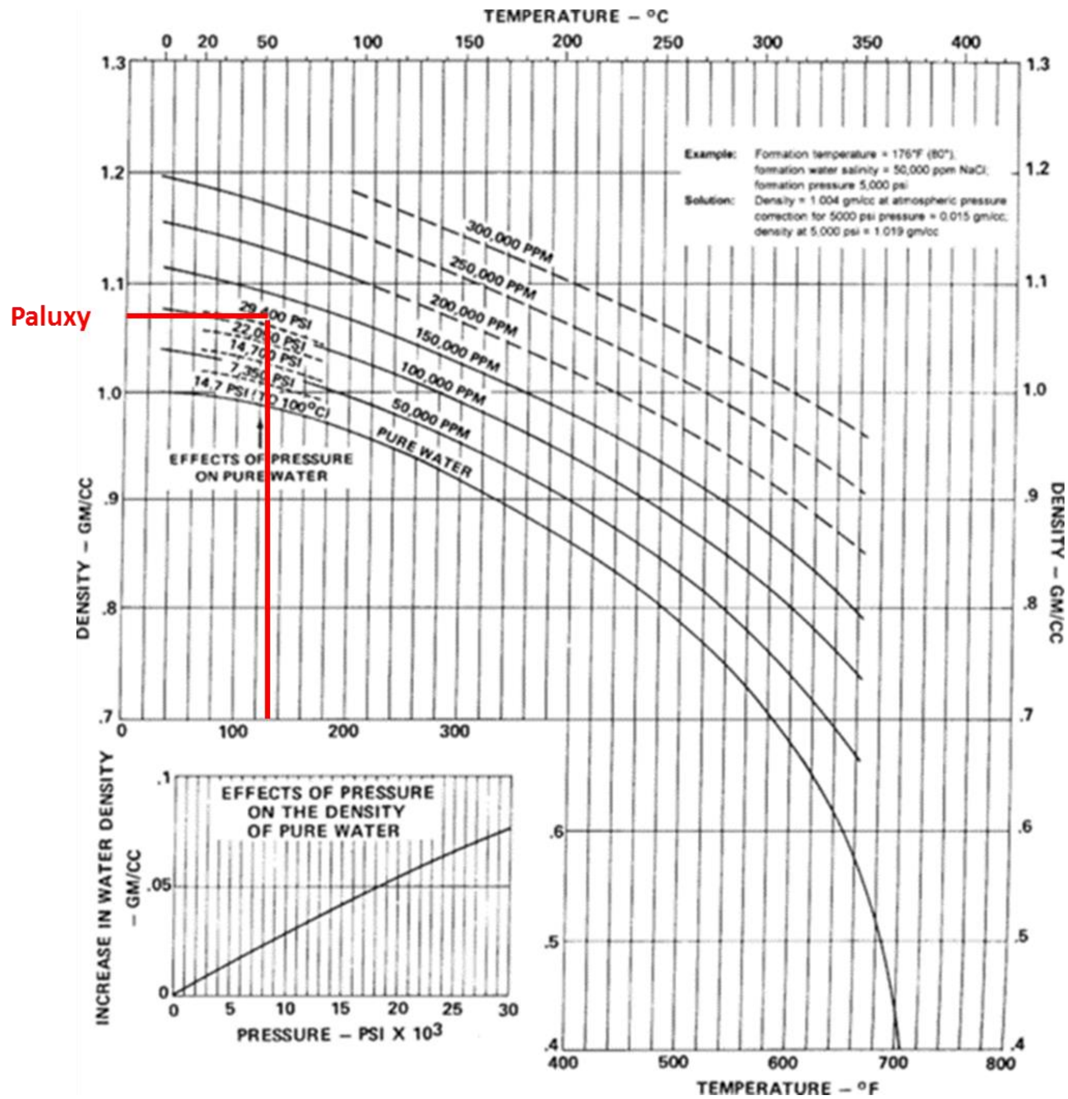

Figure 17: Water Density as a Function of Temperature and TDS (Gearhart-Owens, 1972)

The Rowe and Chou (1970)[1] correlation is employed in the simulation model to compute water density. The modeled mass water density is illustrated on **Figure 18**. The density values compare nicely to the previously mentioned estimated values, **Table 13**.

[1] Rowe, A.M. and Chou, J.C.S., Pressure-Volume-Temperature-Concentration Relation of Aqueous NaCl Solutions, J. Chem. Eng. Data, Vol. 15, (1970), pp. 61-66

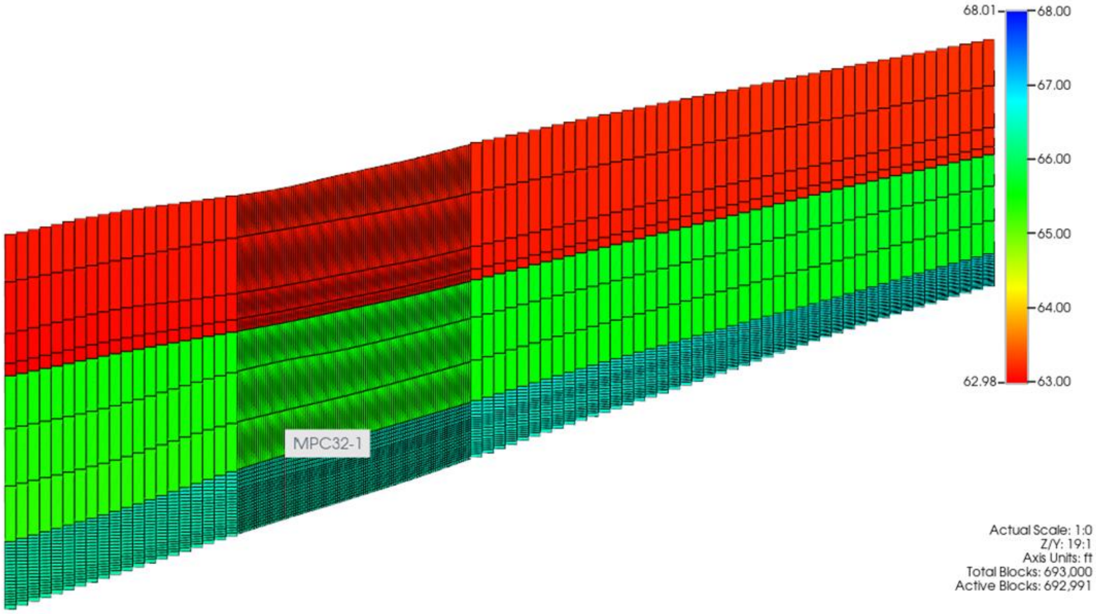

Figure 18: Kemper County Storage Complex Modeled Mass Water Densities

Table 13: Modeled Water Densities

Hydrogeologic Unit	Estimated Density (g/cc)	Modeled Mass Water Density (lbm/ft3)	Modeled Water Density (g/cc)
Lower Tuscaloosa	1.013	63.08	1.011
Washita Fredericksburg	1.057	65.52	1.050
Paluxy	1.075	66.56	1.070

Water Compressibility

Only one data point for water compressibility was available and it was estimated to be 2.87E-6 /psi during the analysis of the pressure fall off test at the MPC34-1 well. This is consistent with correlations of water compressibility as a function of pressure and temperature, McCain (1990)[1].

A.2 Solid-Earth Model

A three-dimensional (3D) model for the proposed Kemper County Storage Complex was developed to fully contain the footprint of the injected CO_2 plume. The

[1] McCain, W.D. Jr. (1990). Properties of Petroleum Fluids (2 ed.). Oklahoma: PennWell Corp. ISBN 978-0878143351.

model captures and incorporates all the modeling parameters detailed in Section 2.1. The area encompassed by the model is shown in red on **Figure 19**: Model Domain for the Proposed Kemper County Storage Complex Geological Model

9. It covers 854 square miles. The model was aligned with a southwest-northeast trend to follow the regional dip in the area.

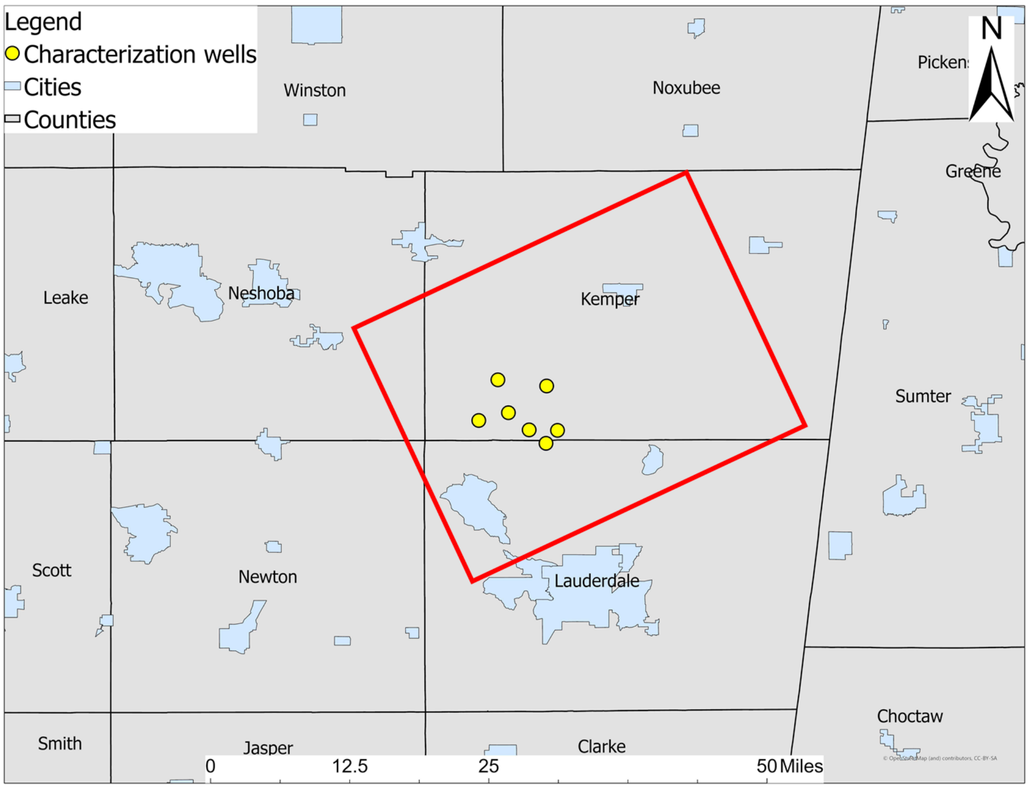

Figure 19: Model Domain for the Proposed Kemper County Storage Complex Geological Model

For the Kemper County Storage Complex, two injection wells are proposed to inject 75 MMscfd (4000 metric tons per day) per well of CO_2 for 30 years. The source of the carbon dioxide for the project are the natural gas-fired electrical generating stations at Plant Ratcliffe located in Kemper County, Mississippi, and Plant Daniel located 150 miles south in Jackson County, Mississippi. The CO_2 will be supplied by pipeline to the injection site. The injection will be into the Lower Cretaceous Paluxy sandstone, a saline reservoir occurring at a depth of approximately 5,000 feet at the injection site. The formation dips to the southwest and it is anticipated that the CO_2 will migrate up-dip towards the northeast. The Tuscaloosa Marine Shale, about 1,600 feet above the top of the Paluxy Formation, serves as the primary confining unit.

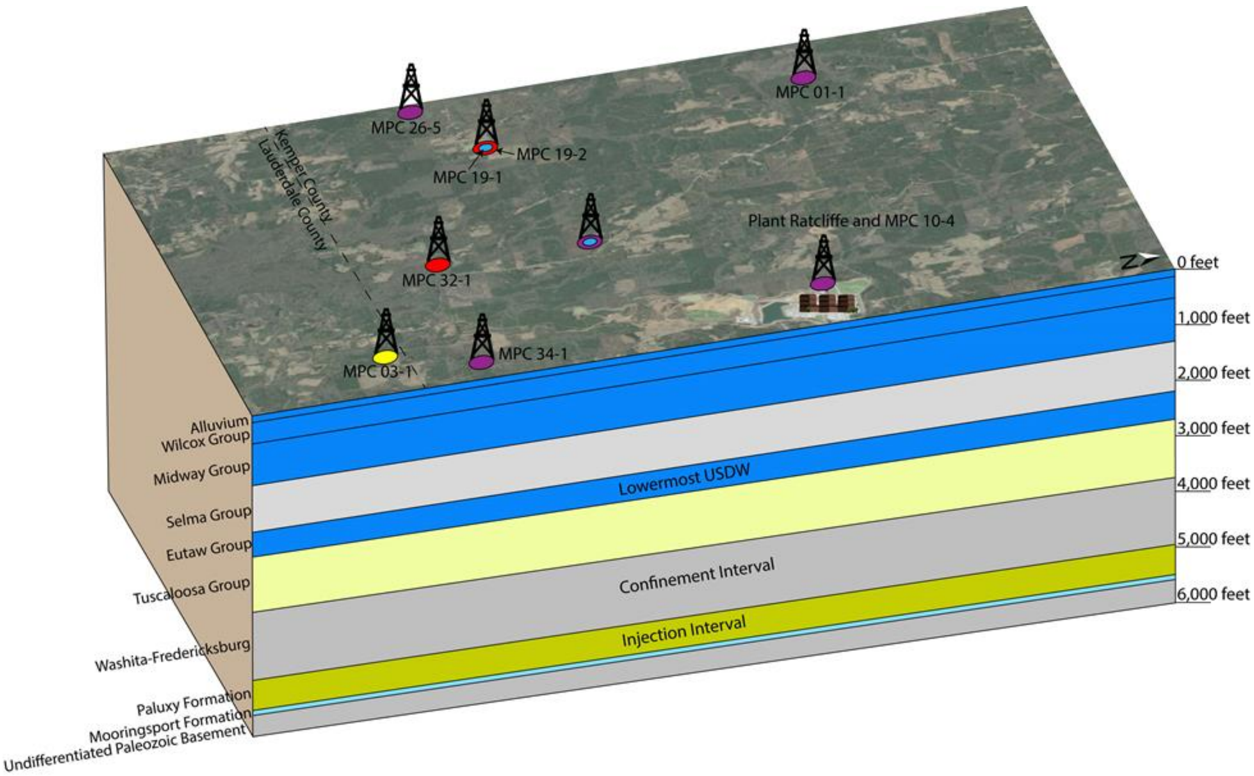

Figure 20: Kemper County Storage Complex Conceptual Model

A.2.a *Model Extent*

The numerical model is rectangular in shape and dimensions of 32.2 x 26.5 miles. The modeled area is oriented with the long axis oriented in the dip direction to account for plume migration in the up-dip direction. The total modeled area covers 545,000 acres. The model was designed as an open boundary system as there are no geological or petrophysical features to act as fluid or pressure propagation boundaries in the model area (see section 1.2 of the *Application Narrative*). A pore volume multiplier of 1,000 was applied to the cells in the model's boundary to simulate an open-boundary system behavior. This approach was chosen over the use of analytical aquifers, which are limited in application to fresh-water systems in the model.

A.2.b *Model Layering*

The two proposed injection wells (MPC 19-2 and MPC 32-1) at the Kemper County Storage Complex will inject into the Paluxy Formation. Information on the injection, confining and overlying formations was collected during the drilling of six characterization wells by MPC. Wireline logs and core analysis were performed at each well. In addition, preexisting 2D seismic lines were acquired within Kemper County to further define the occurrence, extent and thickness of the storage zones and their sealing units. The following is a short description of the geologic setting, lithology, stratigraphy, and hydrology of the Kemper County Storage Complex, which is what the layering of the model is based on.

Kemper County is underlain by sedimentary rock of Cambrian through Tertiary age that is more than 26,000 feet thick and non-conformably overlies the Precambrian crystalline basement (Hale-Ehrlich and Coleman, 1993)[1]. Paleozoic strata range in age from Cambrian through Pennsylvanian and were deposited near the southern tip of a promontory of the ancestral North American continental platform, at what is now the buried juncture of the Appalachian and Ouachita tectonic belts (Thomas, 1977, 1988)[2]. A thick onlapping section of Mesozoic-Cenozoic sediments overlie the Paleozoic section with pronounced angular unconformity (Hale-Ehrlich and Coleman, 1993)[1]; (Pashin et al., 2008)[3]. The Mesozoic-Cenozoic strata were deposited in the Mississippi Embayment of the Gulf of Mexico Basin and form a southwest-dipping wedge of sediment. These deposits range in age from Early Cretaceous at the base, to Tertiary strata of the Naheola and Nanafalia Formations exposed at the surface. The Mesozoic-Cenozoic section is dominated by loosely consolidated sandstone, indurated to soft mudrock, and chalk and

[1] Hale-Ehrlich, W. S., and Coleman, J. L., Jr., 1993, Ouachita-Appalachian juncture: a Paleozoic transpressional zone in the southeastern U.S.A.: American Association of Petroleum Geologists Bulletin, v. 77, p. 552-568.

[2] Thomas, W. A., 1977, Evolution of Appalachian-Ouachita salients and recesses from reentrants and promontories in the continental margin: American Journal of Science, v. 277, p. 1233- 1278.

[3] Pashin, J. C., Hills, D. J., Kopaska-Merkel, D. C., & McIntyre, M. R. (2008). Geological Evaluation of the Potential for CO2 Sequestration in Kemper County. Mississippi: Birmingham, Final Report, Southern Company Research & Environmental Affairs.

marl. The injection and confining zones for the Kemper County Storage Complex are within the Mesozoic-Cenozoic strata.

At the base of the Mesozoic section is a thin, sub horizontal limestone that is assigned to the Lower Cretaceous Mooringsport formation. Overlying the Mooringsport, the sandstones of the Lower Cretaceous Paluxy Formation are the targeted CO_2 injection interval at the proposed Kemper County Storage Complex and have a shallow dip towards the southwest. The Paluxy is divided into four main flow units, which are separated by shale and siltstone that could serve as local, vertical confining units or flow barriers. These flow units were derived from the reservoir characteristics determined through analysis of the electronic logs collected during the characterization phase (**Figure 21**).

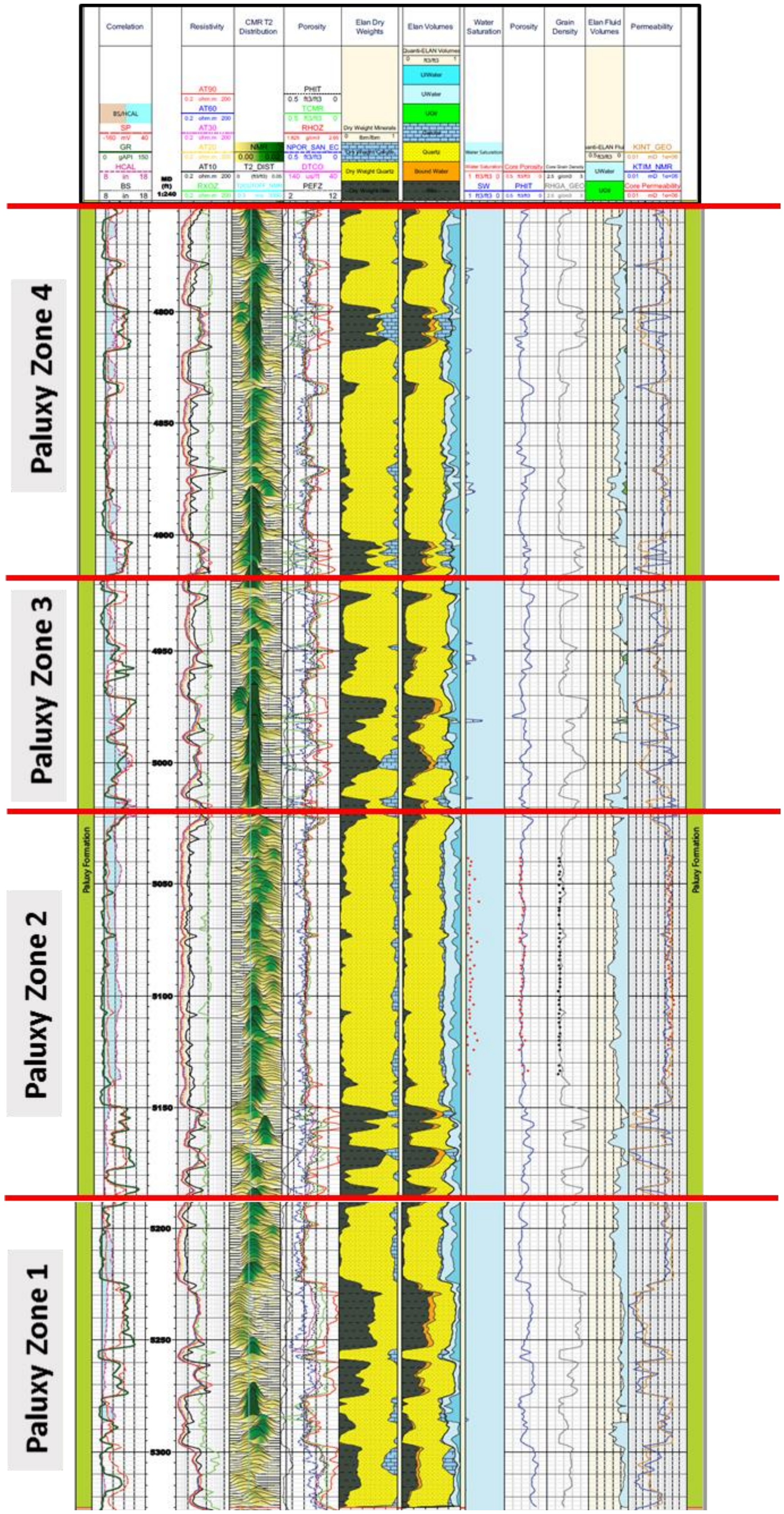

Figure 21: Splitting of Paluxy into Four Zones

The primary confining zone for injection is the Tuscaloosa Marine Shale which isolates USDWs in the upper Tuscaloosa and Eutaw formations from saline aquifers in the lower Tuscaloosa and Dantzler sandstones. Secondary confinement intervals include the Selma Group and Porters Creek clay, which isolate overlying Paleocene and Eocene freshwater aquifers of the Naheola and Nanafalia formations, the unnamed shale member of the middle Washita-Fredericksburg, which is located immediately above the Big Fred sand, and the unnamed basal shale member of the Washita-Fredericksburg group, which is located immediately above the Paluxy Formation.

Figure 22 is a stratigraphic chart with the main Mesozoic and Cenozoic stratigraphic units at the proposed Kemper County Storage Complex. The local freshwater aquifers and potential USDWs are indicated, as well as the proposed CO_2 storage reservoir and five confining units. Below the basal Mesozoic unconformity, a thick confining unit at the top of the Paleozoic section is expected to isolate underlying Paleozoic sediments from fluids contained in Mesozoic reservoirs. Due to the thickness of the Paluxy Formation and to achieve a better resolution of the CO_2 plume extent and to model buoyancy effects, each of the four Paluxy zones were subdivided into five layers. This resulted in 20 sub-layers within the Paluxy and layer thicknesses ranging from approximately 10 feet to 20 feet. As a result, the model has a total of 28 layers (12 main flow units), as summarized in **Table 14**. To account for the presence of the shale at the base of each Paluxy zone acting as vertical flow barriers, zero vertical transmissibility was applied in the model, so no communication is allowed between the four Paluxy flow units. The vertical transmissibility will be part of the sensitivity analysis to understand its impact on injectivity and the size of the CO_2 plume, which is discussed in the *Post Injection Site Care Plan*.

System	Series		Stratigraphic Unit	Major Sub-Units	Potential Reservoirs and Confining Units	
Quaternary	Holocene		Alluvium		Shallow Alluvial Aquifers	
Tertiary / Paleogene	Eocene	Lower	Wilcox Group	*Undifferentiated*	Freshwater Aquifer	
	Paleocene	Upper		Nanafalia Fm.		
			Midway Group	Naheola Fm.	Freshwater Aquifer	
				Porters Creek Clay	Aquitard	
		Lower		Clayton Fm.		
Cretaceous	Upper		Selma Group	Owl Creek / Prairie Bluff Fm.	Aquitard	
				Ripley (McNairy) Fm.		
				Demopolis Fm.		
				Mooreville Fm.		
			Eutaw Group	Tombigbee Sand	USDW	
				McShann Fm.		
			Tuscaloosa Group	Upper Tuscaloosa (Gordo Fm.)	Confining Zone	Model Vertical Extent
				Tuscaloosa Marine Shale	Confining zone	
				Lower Tuscaloosa Massive Sand	Saline Reservoir	
	Lower		Washita-Fredericksburg	Dantzler Fm.	Saline Reservoir	
				Undifferentiated Upper Shale	Confinement Interval	
				'Big Fred' Sand	Saline Reservoir	
				Undifferentiated Basal Shale	Confinement Interval	
			Paluxy Formation		Injection Interval	
			Mooringsport Formation		Limestone Marker	
Paleozoic Undifferentiated			Pennsylvanian Pottsville Fm?		Regional Confining Unit	

Figure 22: Kemper County Storage Complex Stratigraphic Column

Table 14: Kemper County Storage Complex Model Layering

Flow Unit	Layer Number	Formation	Type
1	1	Upper Tuscaloosa	Confining Unit
2	2	Tuscaloosa Marine Shale	Confining Unit
3	3	Massive Sand	Saline Reservoir
4	4	Dantzler	Saline Reservoir
5	5	Upper Washita Fredericksburg	Confining Unit
6	6	Big Fred	Saline Reservoir
7	7	Lower Washita Fredericksburg	Confining Unit
8	8 to 12	Paluxy Zone 4	Injection Zone
9	13 to 17	Paluxy Zone 3	Injection Zone
10	18 to 22	Paluxy Zone 2	Injection Zone
11	23 to 27	Paluxy Zone 1	Injection Zone
12	28	Mooringsport	Limestone Marker

Layer Elevation and Thickness

Elevation maps for the 12 main flow units were generated using the Petra™ software. **Figures 23a and 23b** are an illustration of the elevation map for Zone 4 of the Paluxy Formation in Petra™ and its corresponding map in the numerical simulator for the top Paluxy sandstone. This was directly input to the simulation model. All maps were generated using the North American Datum 1927 (NAD27) system so all maps refer to a system with X and Y coordinates in feet. For each of the 12 main flow units, elevations were picked at three locations, specifically the MPC 10-4, MPC34-1 and MPC26-5 well locations, and maps were generated based on those three data points, using highly connected features (least squares) gridding approach extrapolation in Petra™. The elevation picks for all flow units are summarized in **Table 15**.

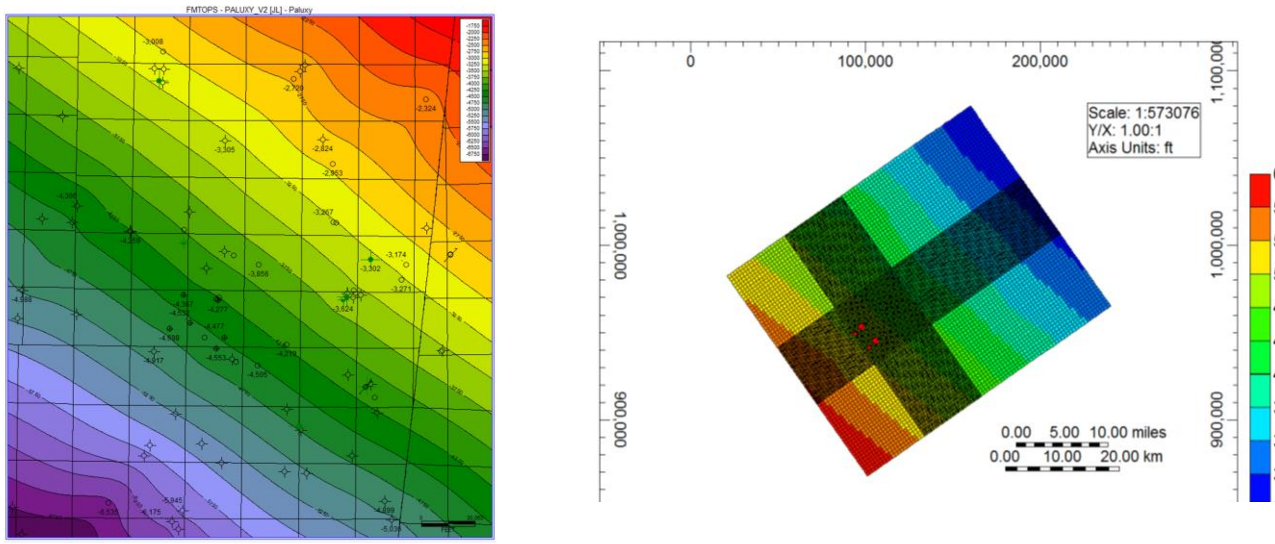

Figure 23: PetraTM Elevation Map of Paluxy Zone 4 (a) and its Corresponding GEM Map (b)

Table 15: Flow Units Tops' Estimates (Measured Depth in Feet)

Flow Unit	MPC 26-5	MPC 34-1	MPC 10-4
Upper Tuscaloosa	2,607	2,603	2,518
Tuscaloosa Marine Shale	3,089	2,935	2,857
Massive Sand	3,598	3,430	3,382
Dantzler	3,820	3,650	3,644
Upper Washita Fredericksburg	3,936	3,754	3,699
Big Fred	4,278	4,148	3,989
Lower Washita Fredericksburg	4,696	4,558	4,401
Paluxy Zone 4	5,160	4,956	4,753
Paluxy Zone 3	5,339	5,130	4,922
Paluxy Zone 2	5,456	5,228	5,023
Paluxy Zone 1	5,642	5,360	5,185
Mooringsport	5,725	5,484	5,300

Once the elevation maps for the 12 main formations were uploaded into the model, the thickness for each layer was computed internally as being the difference between the top of the layer of interest and the top of the underlying layer (**Equation 6**).

$$\text{Thickness (layer n)} = \text{Elevation (layer n)} - \text{Elevation (layer n+1) in feet} \quad \textbf{(6)}$$

This resulted in the 3D view shown in **Figure 24**. A 15:1 vertical to horizontal ratio was implemented to ease the viewing.

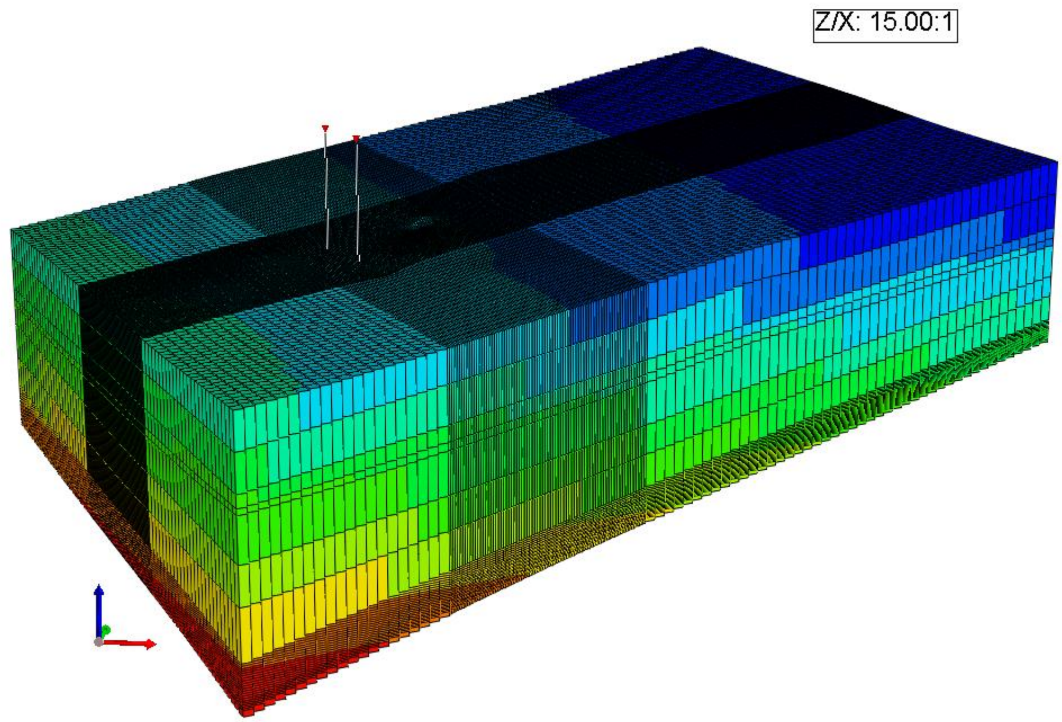

Figure 24: Kemper County Storage Complex Model 3D View (Formation Depth Shown)

Net to Gross

A net to gross ratio was applied in each sand layer to consider the proportion of shale in each sand, which would impede CO_2 movement. **Table 16** shows best estimates for net to gross ratio based on 50% shale cutoff at the MPC10-4 well and logs at MPC26-5 and MPC34-1. The corresponding average value was calculated for each flow unit and implemented in the model.

Table 16: Kemper County Storage Complex Net to Gross Ratio Estimates

Flow Unit	MPC 26-5	MPC 34-1	MPC 10-4	Average
Upper Tuscaloosa	1	1	1	1
Tuscaloosa Marine Shale	1	1	1	1
Massive Sand	0.99	0.98	0.92	0.96
Dantzler	0.95	0.99	1.0	0.98
Upper Washita Fredericksburg	1	1	1	1
Big Fred	0.94	0.85	0.9	0.90
Lower Washita Fredericksburg	1	1	1	1
Paluxy Zone 4	0.72	0.75	0.88	0.78
Paluxy Zone 3	0.74	0.83	0.7	0.76
Paluxy Zone 2	0.9	0.68	1	0.86
Paluxy Zone 1	0.87	0.72	0.62	0.74
Mooringsport	1	1	1	1

Grid Cell Size

Several studies have been carried out to test the impact of gridding on plume movement[1] .They all conclude that some grid refinement is required around the injection site to better simulate buoyancy and near well-bore effects, while coarser grids can be implemented further away, closer to the model boundaries. To minimize computational processing time and to better define the CO_2 movement, a tartan grid was utilized to model the Kemper County Storage Complex. Grid blocks in the vicinity of the injection wells (over an area of 36,700 acres) measure 400 feet by 400 feet. Further away from the injection wells, where the plume is not anticipated to go, grid blocks can measure up to

1 Doughty, C., & Pruess, K. 2004. Modeling supercritical carbon dioxide injection in heterogeneous porous media. Vadose Zone Journal, 3(3):837–847.
Juanes, R., Spiteri, E.J., Orr Jr., F.M., & Blunt, M.J. 2006. Impact of relative permeability hysteresis on geological CO2 storage. Water Resources Research, 42. W12418.
Doughty, C., Freifeld, B.M., & Trautz, R.C. 2007. Site characterization for CO2 geologic storage and vice versa – the Frio brine pilot, Texas, USA as a case study. Environmental Geology, DOI 10.10007/s00254-007-0942-0.
Yamamoto, H., & Doughty, C. 2009. Investigation of gridding effects for numerical simulation of carbon dioxide geologic sequestration," Proceedings of TOUGH Symposium, LBNL., September 2009, Berkeley, CA.

2,000 feet by 2,000 feet. There are 165 grid blocks along the dip direction and 150 blocks across the model. The grid is shown on **Figure 25**.

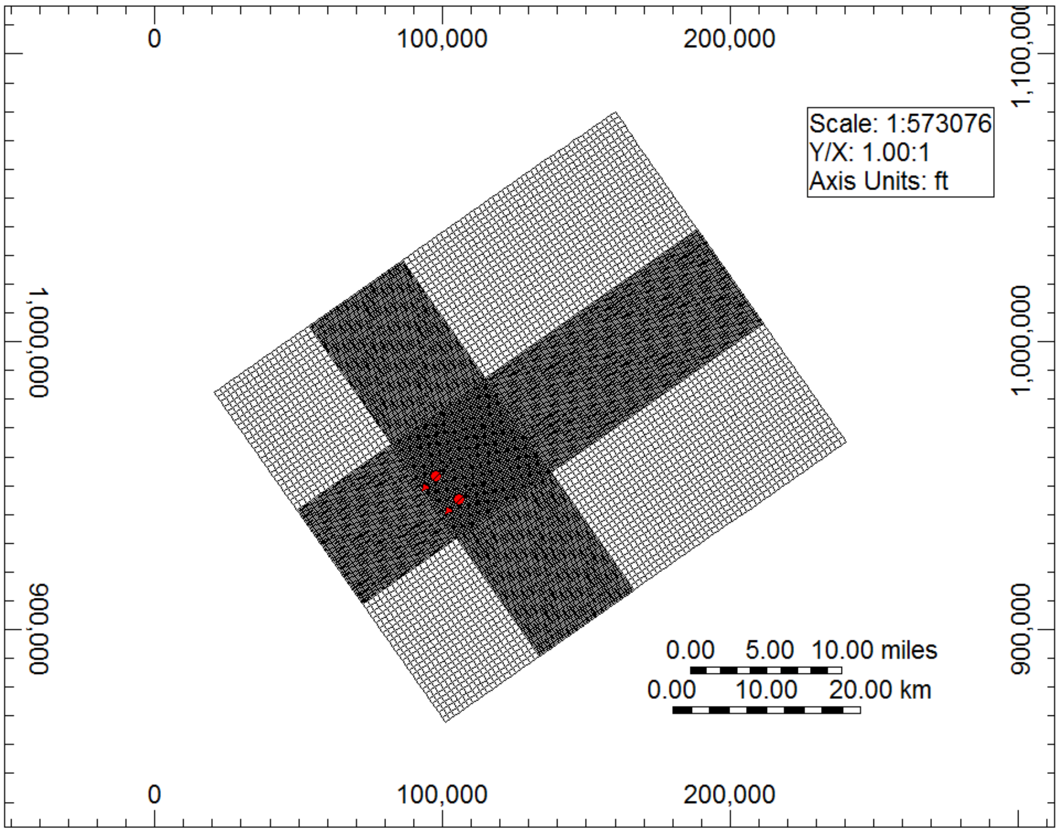

Figure 25: Kemper Model Gridding View

A.2.c *Model Timeframe*

Under Class VI rules, the proposed Class VI injection needs to be simulated from the beginning of injection activities until the plume movement ceases and pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director [40 CFR146.93 (b)(1)]. Research by Flett *et al*. (2007)[1] [2]has shown that, to meet these requirements, it may be necessary for the model simulation of the project to extend for several hundred or thousands of years. Due to the high permeabilities

[1] Flett M., Gurton, R., & Weir, G. 2007. Heterogeneous saline formations for carbon dioxide disposal: Impact of varying heterogeneity on containment and trapping. *Journal of Petroleum Science and Engineering*, 57:106-118.

[2] Freeze, R.A., and Cherry, J.A., 1979, Groundwater: Englewood Cliffs, NJ, Prentice-Hall, 604 p.

of the Paluxy, the likelihood of plume extending post-injection is high. Through iterative modeling, a 150-year post injection timeframe was found to be sufficient to capture plume stabilization.

A.2.d *Model Parameterization*

The final construction step consists of populating the computational model with all the site-specific parameters defined in Section 2.1 (such as, but not limited to porosity, permeability, water properties, formations' elevation and thickness, pressure and temperature). As examples, **Figures 26 to 28** show the porosity, horizontal permeability and initial pressure, implemented into the computational model.

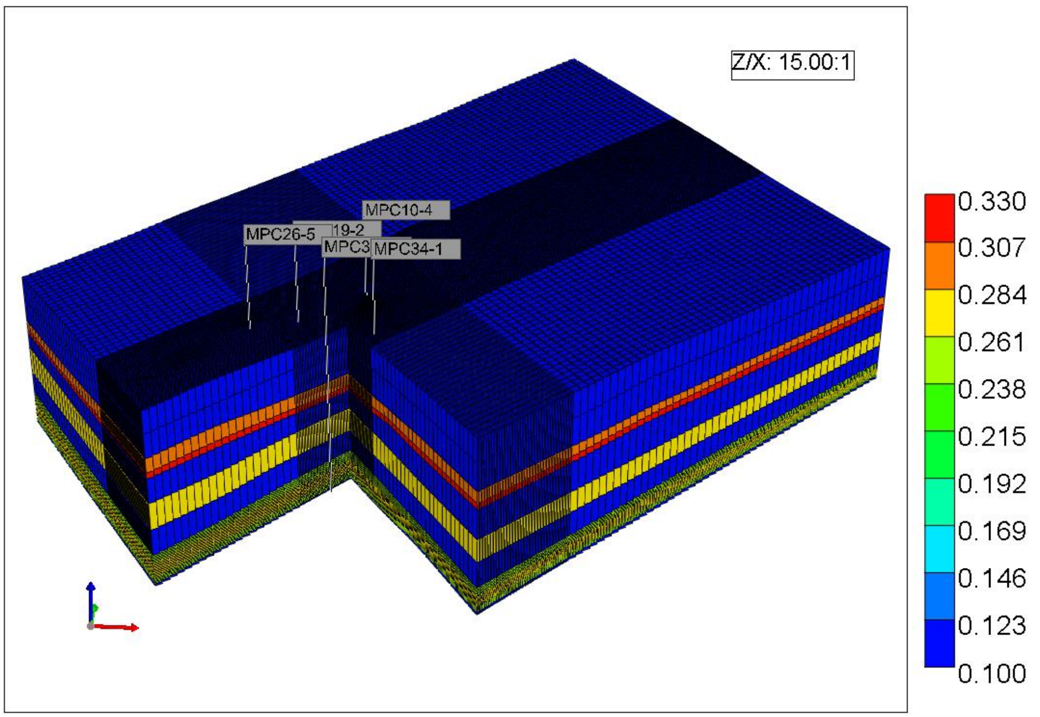

Figure 26: Kemper County Storage Model Porosity (Fraction) Variation Between Formations

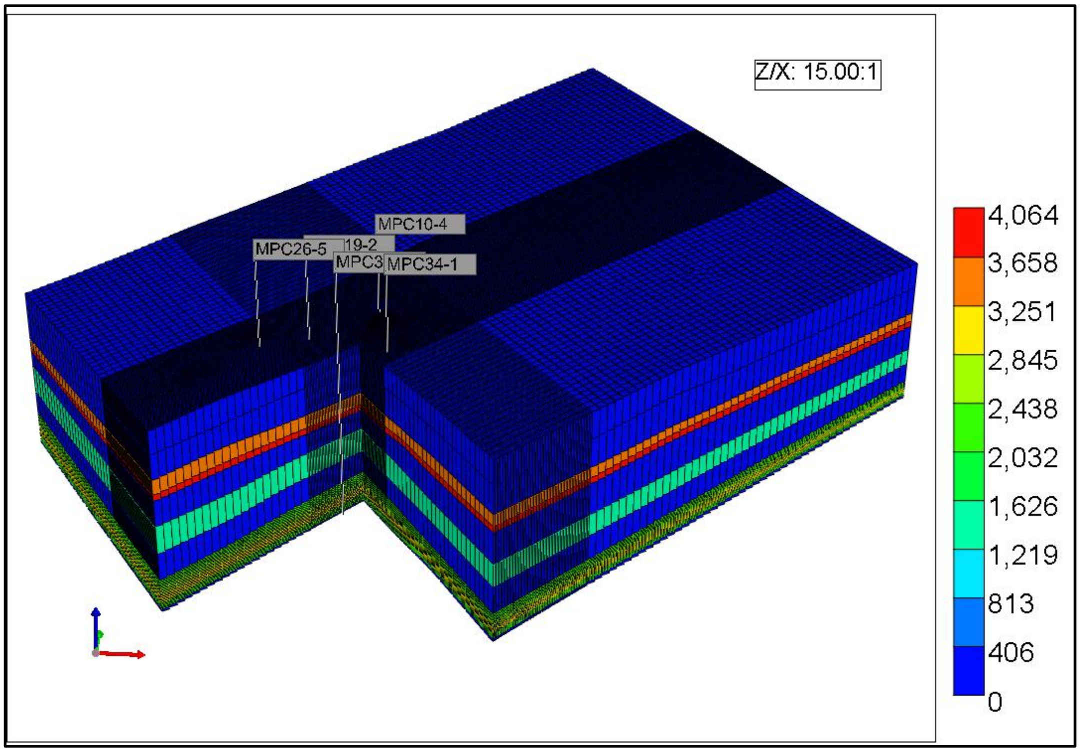

Figure 27: Kemper County Storage Complex Model Permeability (mD) Variation Between Formations

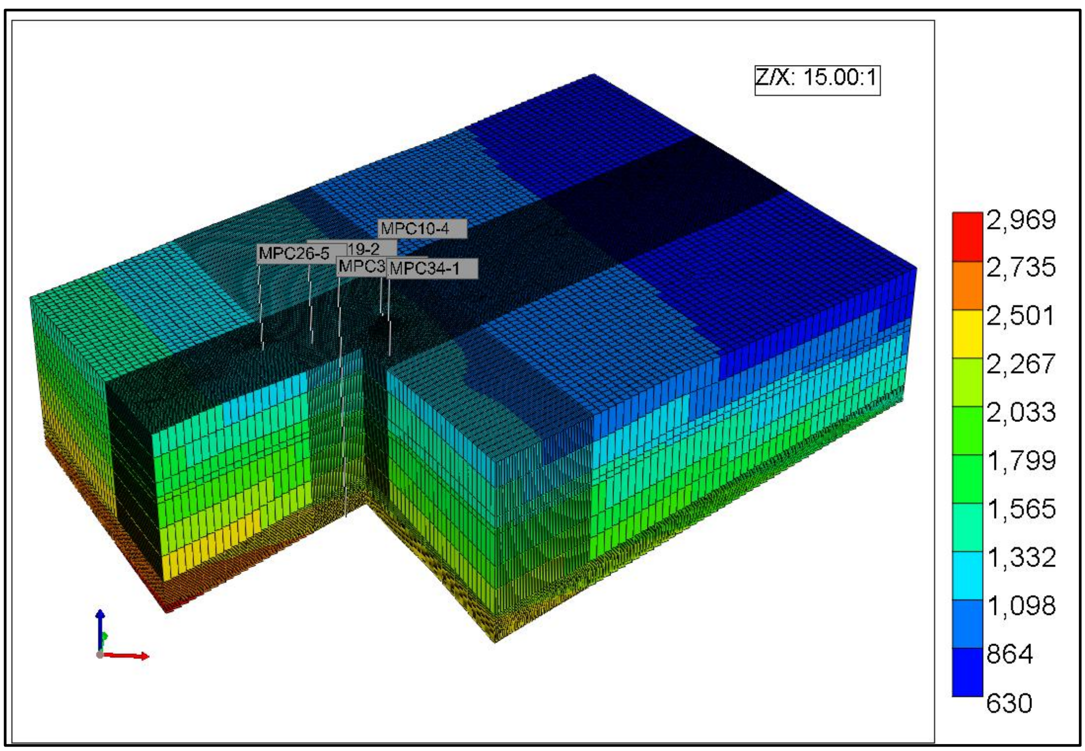

Figure 28: Kemper County Storage Complex Model Initial Pressure (psia)